$\frac{R^2}{A} \rightarrow V^+$

Standing Out

Southwestern Energy Company
2001 Annual Report

With performance:

- **11%** Organic production growth
- **224%** Reserve replacement ratio*
- **$1.11** Finding and development cost per Mcfe*
- **$46** Long-term debt reduction (in millions)

$$\frac{R^2}{A} \rightarrow V^+$$

The answer is in the formula.

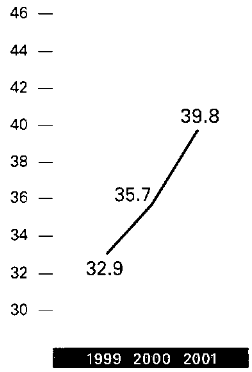
Dear Shareholders: We are pleased to report that 2001 was a very successful year for Southwestern Energy. Southwestern's financial position was strengthened as we grew our production, increased our reserves and made a substantial reduction in our long-term debt. The numbers on the facing page tell the story of last year's performance.

Our drilling results in 2001 generated 11% production growth and 224% reserve replacement at a finding and development cost of $1.11 per Mcfe, excluding revisions. In addition, record production levels combined with higher natural gas prices to produce the highest levels of earnings and cash flow in the Company's history. Net income increased over 70% to $35.3 million and cash flow from operations rose 37% to $112.7 million. These favorable financial results allowed us to pay down $46 million of debt during the year.

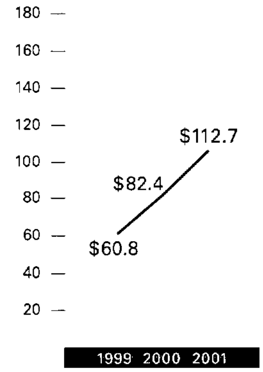
So, what is behind our performance?

Since 1999, we have talked a lot about the importance of having the right team of people and creating an environment that fosters the generation of ideas. We have emphasized doing the right things – selecting the right strategies to create value for our shareholders. We believe the increasingly positive results of the past three years are confirmation of our original formula for success.

 The right people doing the right things, wisely investing the cash flow from the underlying assets will create value +.



Production (Bcfe)



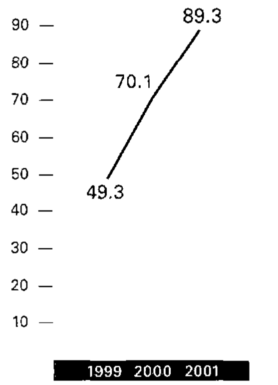
Cash Flow (millions)

Our overall strategy emphasizes a balance of risk in our capital program. The combination of the dependability of cash flow and earnings from our gas distribution business and our low-risk drilling projects in the Arkoma Basin and East Texas have allowed us to aggressively pursue the higher potential returns in our South Louisiana exploration projects. This mix of activity has the benefit of a predictable and consistent base with a high-return exploration element that allows us to exploit our strategic E&P advantages.

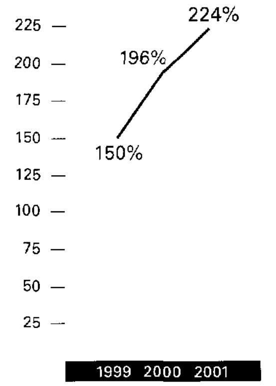
As you look at the cover of our Annual Report you may wonder about the message. For one looking to invest in a publicly traded energy company, the field must sometimes look like that board of wrenches. Upon close inspection; however, you'll see that one wrench stands out – in focus – from the rest. As you look closely at Southwestern Energy you'll see that, like that wrench, we are beginning to stand out as a strong energy company that is focused on creating value.

Why are we different and why should you be interested? As we have repeated over the past few years – it is all about the formula: $\frac{R^2}{A} \rightarrow V^+$

We believe that we have the Right People doing the Right Things, wisely investing the cash flow from the underlying Assets to create Value for our shareholders. We believe that the measure for adding value is PVI, or discounted value added per dollar invested. Over the past three years, our target has been to add at least $1.30 of discounted value for every dollar we invest in exploration and production. I am proud to report that we have achieved that.



Reserve Additions (Bcfe)



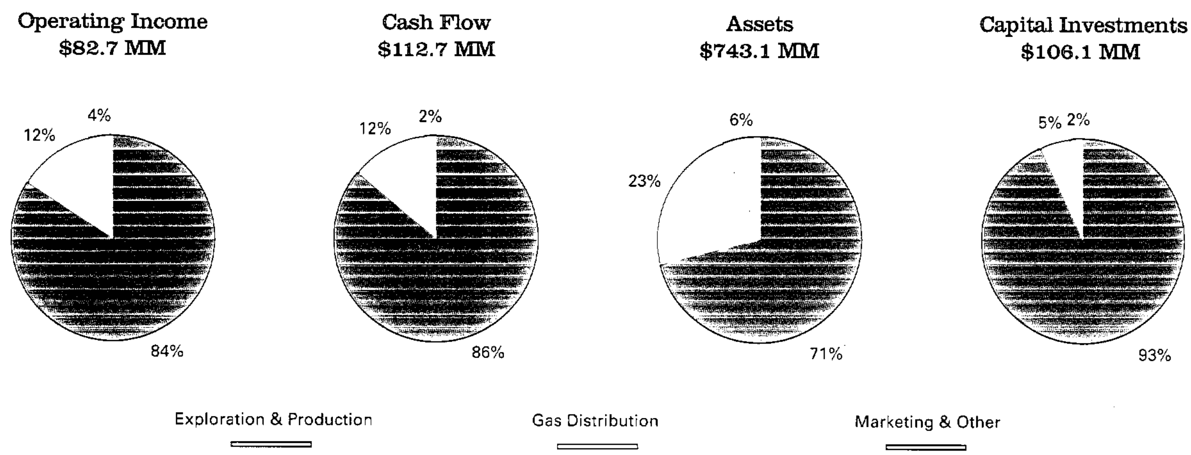
Reserve Replacement

As we go forward into 2002, we must be increasingly vigilant in managing our business. The unseasonably mild winter has resulted in high storage inventories and gas prices that are currently significantly lower than in 2001. We are fortunate to have a balanced inventory of exploration and development opportunities that allows us to easily adjust our capital program during the current soft market that we find ourselves in. We continue to believe that the long-term fundamentals for the natural gas market are very strong.

In closing, I want to thank the shareholders who have supported us over the past few years and the employees who have shown a level of initiative, wisdom and dedication that has produced much-improved results for our shareholders. Looking forward I can only be optimistic as we build on the foundation we have laid in the past three years.

Harold M. Korell
President and Chief Executive Officer

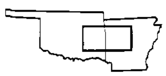
The right people doing the right things, wisely investing the cash flow from the underlying assets will create value +.


Operating Income
$82.7 MM
4%
12%
84%
Cash Flow
$112.7 MM
2%
12%
86%
Assets
$743.1 MM
6%
23%
71%
Capital Investments
$106.1 MM
5%
2%
93%
Exploration & Production
Gas Distribution
Marketing & Other

Revenues and Earnings	2001	2000	1999
Operating revenues (in millions)	$ 344.9	$ 363.9	$ 280.4
Operating income (in millions)	$ 82.7	$ 57.8 [1]	$ 36.1
Net income (in millions)	$ 35.3	$ 20.5 [1]	$ 9.9
Diluted earnings per share	$ 1.38	$ .82 [1]	$ .40
Cash flow from operations (before working capital changes) (in millions)	$ 112.7	$ 82.4 [1]	$ 60.8
EBITDA (in millions)	$ 134.9	$ 103.8 [1]	$ 76.7
Capital expenditures (in millions)	$ 106.1 [2]	$ 75.7	$ 67.0
Average diluted shares outstanding (in millions)	25.6	25.0	24.9
Exploration and Production			
Total proved reserves (Bcf equivalent)	402.0	380.5	354.7
Percent of reserves natural gas	89 %	87 %	87 %
Percent of reserves proved, developed	80 %	82 %	83 %
Total production (Bcf equivalent)	39.8	35.7	32.9
Average gas price ($/Mcf)	$ 3.85	$ 2.88	$ 2.21
Average oil price ($/barrel)	$ 23.55	$ 22.99	$ 17.11
Finding and development cost ($/Mcfe) [3]	$ 1.11	$ 0.99	$ 1.20
Reserve replacement ratio [3]	224 %	196 %	150 %
Reserve life (years)	10.1	10.7	10.8
Natural Gas Distribution [4]			
Total throughput (Bcf)	27.1	29.8	29.1
Utility customers at year-end	136,242	135,534	133,200
Heating weather - percent of normal	91 %	100 %	79 %

(1) Before unusual and extraordinary items.
(2) Includes $13.5 million funded by the owner of the minority interest in Overton partnership.
(3) Excludes reserve revisions.
(4) Gas distribution statistics exclude results from the Company's Missouri utility operations that were sold in May 2000.

 The right people doing the right things, wisely investing the cash flow from the underlying assets will create value +.



Reserves – 186.0 Bcf
Production – 22.3 Bcf
2001 Capital – $28.6 million

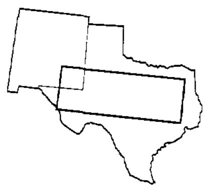
Arkoma Basin Representing the solid foundation of the Company's exploration and production program, the Arkoma Basin continues to provide a stable production stream and reserve base year after year. In 2001, Southwestern continued its track record of producing excellent results from this basin.

During 2001, Southwestern successfully completed 42 wells out of 52 drilled for a success ratio of over 80%. The Company also experienced production growth from the basin in 2001, as natural gas production was up 12% over 2000 levels. Until 2001, the Company had experienced declining production in the Arkoma for the past eight years.

The main driver behind the growth in production was the Company's success at its Haileyville prospect in Pittsburg County, Oklahoma. Southwestern encountered high-deliverability gas sands in the prospect which, at its peak in late-June, had two wells separately producing at gross rates of over 20 million cubic feet of gas per day (MMcf/d). The results of the Company's success at Haileyville added a net of approximately 5 billion cubic feet (Bcf) of gas reserves in 2001.

The Company's strategy for the Arkoma is to continue its exploitation drilling and workover programs at a level to maintain its production and reserve base. The Company also plans to begin testing new exploration prospect areas on the southern edge of the basin, similar to its Ranger Anticline play, where it has drilled 10 successful wells out of 14.

For more than 50 years, Southwestern has built its competitive advantage in the Arkoma through its people. This experience, coupled with a dominant land position of over 230,000 net acres and a superior geologic database, are the keys that will continue to unlock value for Southwestern in the Arkoma for years to come.



Reserves – 137.0 Bcfe
Production – 9.9 Bcfe
2001 Capital – $44.9 million

Texas/New Mexico In 2001, Southwestern commenced an infill drilling program at its Overton Field, located in East Texas, and continued its exploration and exploitation program in the Permian Basin.

The Company drilled 15 successful wells in the Cotton Valley Sand formation at its Overton Field during the year. Daily production at Overton increased from 2 MMcf equivalent (MMcfe) in March of 2001 to approximately 16 MMcfe at year-end, resulting in production of 2.3 Bcf equivalent (Bcfe) net to Southwestern during 2001. An important factor in the Company's success involves applying enhanced fracture stimulation techniques on this tight-sand formation. As a result, initial daily production rates averaged approximately 3.5 MMcfe per well, more than double the initial production rates from the existing wells that were drilled by the field's previous owner. The Company's proved reserves at Overton increased to 58 Bcfe at year-end 2001 up from 22 Bcfe at the end of 2000.

Overton provides the Company with a low-risk multi-year drilling program and significant production and reserve growth potential. This is due to the level of infill drilling that is possible in the field over the next several years. When purchased by Southwestern in April of 2000, the majority of the field was drilled on 640-acre spacing, or one well per square mile. Analogous Cotton Valley fields in the area have been drilled to 80-acre spacing or less. By downspacing the field to 80-acre spacing, Southwestern could have an additional 90 drilling locations. The Company plans to drill five to ten wells at Overton in 2002.

In West Texas and Southeast New Mexico, the Company continued to pursue its strategy of medium-risk exploration and exploitation in the Permian Basin. The Company drilled 19 successful wells out of 26 in the Permian in 2001. Included were three wells in the Company's Roepke prospect in Crane County, Texas, which added 3.3 Bcfe of new reserves. Southwestern plans to continue to pursue its strategy in the Permian Basin, albeit at a slower pace. The Company plans to invest approximately $8 million in the Permian in 2002, which includes drilling up to 14 wells.

 The right people doing the right things, wisely investing the cash flow from the underlying assets will create value +.

Reserves – 42.4 Bcfe
Production – 4.8 Bcfe
2001 Capital – $24.6 million

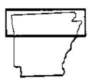
Louisiana Southwestern's exploration success continued in 2001 with three meaningful discoveries in South Louisiana. Since the first exploration discovery at the Company's Gloria prospect in December 1999, Southwestern has posted an impressive track record in the area with six successful wells out of the last nine drilled.

In January, the Company announced a discovery at its Malone prospect, located five miles south of the discovery at Gloria in Assumption Parish. The discovery well encountered approximately 260 feet of gas pay in five separate productive sands within the Miocene formation. The prospect is currently producing from two wells at a combined daily gross rate of 27.0 MMcf/d and 525 barrels of oil (Bopd).

After drilling dry holes at Whitehorse and Mahone, the Company found 50 feet of gas pay in its Horeb prospect in Acadia Parish. That well was placed on production in November and is currently producing at a gross rate of 12.6 MMcf/d and 160 Bopd. In December, the Company announced a discovery at its Crowne prospect in Cameron Parish. The well encountered 75 feet of pay and was placed on production at 10.0 MMcf/d and 35 Bopd in February 2002. The Company is currently drilling a second well in the prospect to further delineate and develop the reservoir.

In February 2002, the Company announced that its first development well on the Company's North Grosbec discovery in Assumption Parish, the Raymond Egle #1, began production at a gross daily rate of 20.0 MMcf/d and 800 Bopd. This well was designed to further develop the Planulina objective, which is currently producing in the discovery well at 15.0 MMcf/d and 550 Bopd.

In 2002, the Company plans to invest approximately $23 million in the Gulf Coast region, which includes up to eight exploration tests and a new 3-D project that will provide fuel for future growth. Southwestern's new 3-D project in St. Martin and St. Mary Parishes will cover approximately 140-square miles in a prospective area. This seismic data is expected to be delivered in the third quarter of 2002.



Customers – 136,242
2001 Throughput – 27.1 Bcf
2001 Weather – 91% of normal

Natural Gas Distribution

The economy in the Company's Northwest Arkansas service territory continues to thrive due to the robust growth of area corporations and the attractive quality of life that the region offers. In April 2001, the U.S. Census Bureau named Northwest Arkansas as the 6th fastest growing community in the United States. The area population grew 47.5%, or 4.0% annually, over the past ten years. As home to the largest public corporation in the world, Wal-Mart Stores, Inc., the region has enjoyed significant growth due to its presence in the area. Other corporations such as Tyson Foods and J.B. Hunt Transportation have also contributed to the impressive development of this region of the state. Approximately 85% of Southwestern's utility customers are located in this growing region.

Southwestern's natural gas distribution business contributed operating income of $10.3 million during 2001 compared to $12.6 million in 2000, excluding the income from the Company's Missouri gas distribution operations that were sold in May 2000. The operating results of the utility are highly seasonal and the comparative decrease was due to the warmest November - December time period in the Company's history, combined with increased bad-debt expense caused by record high natural gas prices experienced in the first part of 2001. The warm winter of 2001 is in significant contrast to the winter of 2000, which included the coldest November - December time period in the utility's history.

With over 70 years of service to the area, Southwestern's utility continues to provide its customers a dependable and safe energy supply. Southwestern benefits from the predictable earnings and cash flow streams from this low-risk business segment.

Corporate Information

Directors

Lewis E. Epley, Jr. (4)
Attorney at Law

John Paul Hammerschmidt (10)
Retired, U.S. Congressman

Robert L. Howard (7)
Retired, Shell Oil Company

Harold M. Korell (5)
President and Chief Executive Officer
Southwestern Energy Company

Kenneth R. Mourton (7)
Managing Partner, Ball and Mourton, Ltd., PLLC

Charles E. Scharlau (50)
Chairman of the Board
Retired CEO Southwestern Energy Company

Corporate Officers

Harold M. Korell (5)
President and Chief Executive Officer

Greg D. Kerley (12)
Executive Vice President and Chief Financial Officer

Mark K. Boling
Senior Vice President, General Counsel and Secretary

Dee W. Hency (24)
Vice President - Administration and Chief Information Officer

Timothy J. O'Donnell (11)
Vice President - Human Resources and Treasurer

Stanley T. Wilson (16)
Controller and Chief Accounting Officer

Subsidiary Operating Officers

Southwestern Energy Production Company and SEECO, Inc.

Richard F. Lane (4)
Executive Vice President

Jim R. Dewbre (4)
Vice President - Land

J. Alan Stubblefield (4)
Vice President Production

John D. Thaeler (3)
Vice President
SEECO, Inc.

Arkansas Western Gas Company

Charles V. Stevens (30)
Senior Vice President

Ricky A. Gunter (29)
Vice President - Rates and Regulation

Bob Lamb (11)
Vice President
Community Development

Jeffrey L. Dangeau (16)
General Counsel and Secretary

Glenn M. Morgan (25)
Controller and Treasurer

Pictured from left to right
Harold M. Korell,
Greg D. Kerley,
Richard F. Lane,
Mark K. Boling,
Charles V. Stevens

Years of service with the Company are shown in parentheses.

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark one)

☑ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2001

or

☐ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from ____________ to ____________

Commission file number 1-8246

Southwestern Energy Company

(Exact name of Registrant as specified in its charter)

Arkansas	71-0205415
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

2350 N. Sam Houston Parkway East, Suite 300, Houston, Texas 77032
(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code: (281) 618-4700

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock - Par Value $.10	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ✓ No ____

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

The aggregate market value of the voting stock held by non-affiliates of the Registrant was $278,979,412 based on the New York Stock Exchange — Composite Transactions closing price on March 7, 2002, of $11.19.

The number of shares outstanding as of March 7, 2002, of the Registrant's Common Stock, par value $.10, was 25,502,070.

DOCUMENTS INCORPORATED BY REFERENCE

Document incorporated by reference and the Part of the Form 10-K into which the document is incorporated: Definitive Proxy Statement to holders of the Registrant's Common Stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Shareholders on May 15, 2002 - PART III.

TABLE OF CONTENTS

Part I

ITEM 1. BUSINESS

Southwestern Energy Company (the "Company" or "Southwestern") is an energy company primarily focused on natural gas. The Company was incorporated in Arkansas in 1929 as a local gas distribution company. Today, Southwestern is an exempt holding company under the Public Utility Holding Company Act of 1935 and derives the vast majority of its operating income and cash flow from its oil and gas exploration and production business. In February 2001, the Company relocated its corporate headquarters from Fayetteville, Arkansas to Houston, Texas. The Company is involved in the following business segments:

1. Exploration and Production – Engaged in natural gas and oil exploration, development and production, with operations principally located in Arkansas, Oklahoma, Texas, New Mexico, and Louisiana. This represents the Company's primary business.
2. Natural Gas Distribution – Engaged in the gathering, distribution and transmission of natural gas to approximately 136,000 customers in Arkansas.
3. Marketing and Transportation – Provides marketing and transportation services in the Company's core areas of operation and owns a 25% interest in the NOARK Pipeline System, Limited Partnership (NOARK).

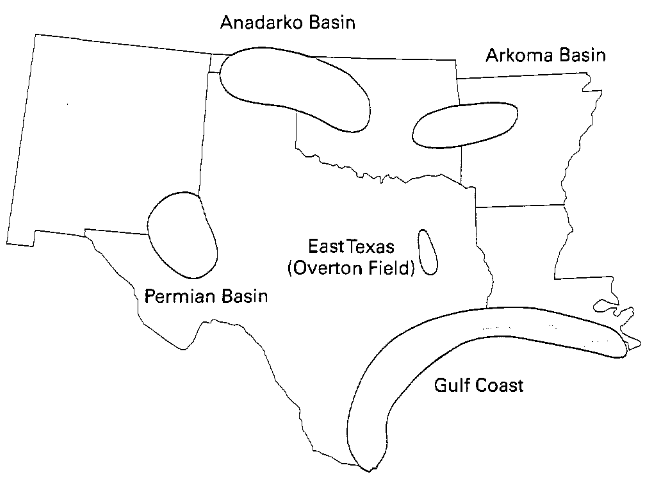
This Report on Form 10-K includes certain statements that may be deemed to be "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of this Report for a discussion of factors that could cause actual results to differ materially from any such forward-looking statements.

Business Strategy

The Company's business strategy is to provide long-term growth through focused exploration and production of oil and natural gas. The Company seeks to maximize cash flow and earnings and provide consistent growth in oil and gas production and reserves through the discovery, production and marketing of high margin reserves from a balanced portfolio of drilling opportunities. This balanced portfolio includes low-risk development drilling in the Arkoma Basin and East Texas, moderate-risk exploration and exploitation in the Permian Basin, and high-potential exploration opportunities in the onshore Gulf Coast region. The Company further enhances shareholder value by creating and capturing additional value beyond the wellhead through its natural gas distribution, marketing and transportation activities.

EXPLORATION AND PRODUCTION

In 1943, the Company commenced a program of exploration for and development of natural gas reserves in Arkansas for supply to its utility customers. In 1971, the Company initiated an exploration and development program outside Arkansas, unrelated to the utility's requirements. Since that time, Southwestern's exploration and development activities outside Arkansas have expanded substantially.



In 1998, Southwestern brought in new senior management for its exploration and production business and has since replaced over 70% of its professional technical staff to refocus its exploration and production effort. Additionally in 1998, the Company closed its Oklahoma City office and moved these operations to Houston in an effort to increase future profitability. The segment was also reorganized into asset management teams to provide an area-specific focus in exploration and development projects and a new incentive compensation system was put in place to more closely align its employees' efforts with the interests of its shareholders. As a result of these changes, the operating results of this business segment have improved substantially over the last few years and, in 2001, the segment set new records for oil and gas production, reserve additions, operating income and cash flow generated from operations.

At December 31, 2001, the Company had proved oil and gas reserves of 402.0 billion cubic feet (Bcf) equivalent, including proved natural gas reserves of 355.8 Bcf and proved oil reserves of 7,704 thousand barrels (MBbls). The Company's reserve life index approximated 10.1 years at year-end 2001, with 80% of total reserves classified as proved, developed. All of the Company's reserves are located entirely within the United States. Revenues of the exploration and production subsidiaries are predominately generated from production of natural gas. Sales of gas production accounted for 89% of total operating revenues for this segment in 2001, 82% in 2000, and 87% in 1999.

Areas of Operation

Southwestern engages in oil and gas exploration and production through its wholly-owned subsidiaries, SEECO, Inc. (SEECO), Southwestern Energy Production Company (SEPCO) and Diamond "M" Production Company (Diamond M). SEECO operates exclusively in the state of Arkansas and holds a large base of both developed and undeveloped gas reserves and conducts an ongoing drilling program in the historically productive Arkansas part of the Arkoma Basin. SEPCO conducts development drilling and exploration programs in the Oklahoma portion of the Arkoma Basin, the Permian Basin of Texas and New Mexico, the Anadarko Basin of Oklahoma, and in Louisiana and Texas. Diamond M operates properties in the Permian Basin of Texas. A wholly-owned subsidiary of SEPCO, Overton Partners, L.L.C., owns an interest in Overton Partners, L.P., a limited partnership formed in 2001 to drill and complete the first 14 development wells in SEPCO's Overton Field in East Texas.

Southwestern replaced 224% of its production in 2001 by adding an estimated 89.3 Bcf equivalent (Bcfe) of proved oil and gas reserves at a finding and development cost of $1.11 per thousand cubic feet equivalent (Mcfe), excluding reserve revisions. The Company's finding cost including the effect of downward reserve revisions due to lower year-end commodity prices was $1.60 per Mcfe in 2001. Southwestern's three-year average finding and development cost was $1.22 per Mcfe, including reserve revisions. The following table provides information as of December 31, 2001 related to proved reserves, well count, and gross and net acreage, and 2001 annual information as to production, reserve additions and capital expenditures for each of the Company's core operating areas.

	Arkoma	Mid-Continent	Texas/ New Mexico	Louisiana	Total
Proved reserves:					
Gas (Bcf)	186.0	28.1	106.9	34.8	355.8
Oil (MBbls)	–	1,426	5,017	1,261	7,704
Total reserves (Bcfe)	186.0	36.6	137.0	42.4	402.0
Production (Bcfe)	22.3	2.8	9.9	4.8	39.8
Reserve additions (Bcfe)	23.2	8.6	43.2	14.3	89.3
Capital expenditures (in millions)	$ 28.6	$ 0.9	$ 44.9	$ 24.6	$ 99.0
Total gross wells	806	551	445	32	1,834
Percent operated	44%	29%	39%	66%	39%
Gross acreage	348,143	62,168	377,863	150,992	939,166
Net acreage	237,511	6,629	114,740	87,526	446,406

Arkoma Basin. The Arkoma Basin provides a solid foundation for the Company's exploration and production program and represents the primary source of production and reserves for the Company. At December 31, 2001, the Company had approximately 186.0 Bcf of natural gas reserves in the Arkoma Basin, representing 52% of the Company's natural gas reserves and 46% of total reserves on a Bcf equivalent basis. The Company participated in 52 wells during 2001 with an 81% success ratio. Southwestern's Arkoma program added 23.2 Bcf of gas reserves at a finding and development cost of $1.23 per thousand cubic feet (Mcf) in 2001. The Company's natural gas production in the basin was 22.3 Bcf, a 12% increase over production levels in 2000. Until 2001, Southwestern had experienced declining production in the Arkoma over the past eight years. Average net daily production in 2001 was 61.1 million cubic feet (MMcf/d).

Southwestern's Arkoma Basin operations continue to generate a significant amount of the Company's cash flow. With average three-year finding and development costs of $1.05 per Mcf and three-year average production, or lifting, costs of $.26 per Mcf (including production taxes), the Company's cash margins per well in the Arkoma remain very attractive.

Lifting costs continued to be low during 2001 at $.32 per Mcf (including production taxes). After direct general and administrative expenses of $.14 per Mcf, Southwestern's netback per Mcf after cash expenses was 89% of the average price it realized for its Arkoma production in 2001, including the impact of commodity hedges.

Southwestern's traditional operating area over the years has been in the "fairway" portion of the basin in Arkansas, which is primarily within the boundaries of the Company's utility gathering system. The Company's strategy in this core producing area is to delineate new geologic plays and extend previously identified trends using Southwestern's extensive databank of regional structural and stratigraphic maps. Southwestern completed 14 wells out of 18 drilled in the fairway in 2001 that added 8.3 Bcf of new reserves. Southwestern plans to drill up to 15 wells in the fairway portion of the basin in 2002.

In recent years, Southwestern has extended its development program outside of the traditional fairway area to continue its growth. During 2001, the Company continued the development of its Haileyville prospect in Pittsburg County, Oklahoma, with excellent results. Since initial drilling in the area in 1999, Southwestern has successfully completed 13 out of 20 wells drilled. In 2001, Southwestern encountered high-deliverability gas sands in the prospect which resulted in two wells, the Agnes #1-18 and the Cope #3A, separately producing at gross rates of over 20 MMcf/d. Total production at Haileyville was 3.0 Bcf net to Southwestern in 2001 and the prospect added a net of approximately 5.0 Bcf of new gas reserves from six wells. Southwestern's average working interest in the prospect is approximately 35%.

In 2001, the Company also continued the development of its Ranger Anticline prospect area, located at the southern edge of the Arkansas portion of the basin. To date, the Company has successfully drilled 10 out of 14 wells in this prospect, adding 12.4 Bcf of reserves net to Southwestern's interest at a finding cost of $.69 per Mcf. In 2001, the Company drilled the Catlett #1-13 well which was placed on production at 2.2 MMcf/d with an 80% working interest, resulting in new reserves of 2.7 Bcf. The Catlett #1-13 well is an example of the continued successful development of this complex overthrust play. The Company also plans to begin testing new exploration prospect areas on the southern edge of the basin similar to its Ranger Anticline play.

Additionally, during 2001 the Company initiated an extensive workover program in the Arkoma, which included fracture stimulations, artificial lift, recompletion and wellbore repair projects that provided meaningful production increases. The Company performed 55 of these workover projects in 2001 resulting in production increases totaling 4.4 MMcf/d, at a total cost of $1.4 million.

The Company's strategy for the Arkoma is to continue its exploitation drilling and workover programs at a level to maintain its production and reserve base. In 2002, Southwestern plans to invest approximately $18.5 million in the basin to drill approximately 40 wells and perform approximately 50 workovers.

Mid-Continent. Southwestern's activities in this region are primarily focused on the Anadarko Basin of Oklahoma. At December 31, 2001, the Company had approximately 28.1 Bcf of natural gas reserves and 1,426 MBbls of oil reserves in the region, representing 8% and 19%, respectively, of the Company's total gas and oil reserves. Average net daily production in 2001 for this region was 7.7 MMcf equivalent (MMcfe). Southwestern does not expect its Mid-Continent operations to be a primary area of future growth due to its efforts to concentrate on those areas where it has a competitive advantage. The Company intends to produce these properties to depletion, sell them or trade them for properties in the Company's core areas of operation. During 2000, the Company sold at auction a portion of its properties in the Mid-Continent area with proved reserves of 13.8 Bcfe for approximately $13.1 million.

Texas/New Mexico. Southwestern has key operations in the states of Texas and New Mexico, and is primarily focused on its Overton Field in East Texas, and the Permian Basin in West Texas and Southeast New Mexico. At December 31, 2001, Southwestern had proved reserves of 106.9 Bcf of gas and 5,017 MBbls of oil in the region, representing 30% and 65%, respectively, of the Company's total gas and oil reserves.

Overton Field. In April 2000, the Company purchased the Overton Field in Smith County, Texas, from Total Fina Elf for $6.1 million. Estimated initial reserves associated with the purchase were 7.5 Bcfe, for a purchase price of $.81 per Mcfe. The purchase included 16 active gas wells in 13 spacing units, 8,800 contiguous acres in established units and 2,000 additional undeveloped acres outside the units. Overton provides the Company with a low-risk multi-year drilling program and significant production and reserve growth potential. This is due to the level of infill drilling that is possible in the field over the next several years. When purchased by Southwestern in April of 2000, the field was primarily drilled on 640-acre spacing, or one well per square mile. Analogous Cotton Valley fields in the area have been drilled to 80-acre spacing. By downspacing the field to 80-acre spacing, Southwestern could have an additional 90 drilling locations.

During 2001, Southwestern's subsidiary, SEPCO, formed a limited partnership, Overton Partners, L.P., with an investor to drill and complete the first 14 development wells at Overton. This partnership was created to accelerate the development of the field. SEPCO is the partnership's General Partner and contributed 50% of the capital required to drill the first 14 wells.

In return, SEPCO receives 65% of the partnership's available cash distributions prior to payout of the investor's initial investment and 85% of the partnership's available cash distributions after payout. Production and reserve statistics for Overton include 100% of the partnership's activity, and all operating and financial results are incorporated into the Company's consolidated financial statements.

Southwestern drilled a total of 15 wells at its Overton Field during 2001, including 14 development wells in the Overton limited partnership. The wells targeted the Cotton Valley Taylor sand formation at approximately 12,000 feet and all 15 wells were successful. Daily production at Overton increased from 2 MMcfe in March of 2001 to approximately 16 MMcfe at year-end, resulting in production of 2.3 Bcfe net to Southwestern during 2001. The Company's average production cost at Overton was $.53 per Mcfe in 2001. Southwestern's proved reserves at Overton increased to 57.6 Bcfe at year-end 2001, up from 22.0 Bcfe at the end of 2000. The Company invested approximately $30.9 million in its drilling program at Overton during 2001, including $13.5 million funded by the owner of the minority interest in the Overton partnership. The capital investments resulted in reserve additions of 37.8 Bcfe, for a finding and development cost of $.82 per Mcfe. Southwestern's average working interest in the field is 97% and average net revenue interest is 80%. Southwestern expanded its position in the Overton area during 2001 through a farm-in of approximately 5,800 adjacent acres. The acreage contains nine 640-acre units, most of which have only been drilled to 640-acre spacing. The Company has contracted to drill a minimum of two wells on this acreage in 2002. In total, Southwestern plans to invest approximately $12 million to drill 5 to 10 wells in the Overton Field area during 2002.

Permian Basin. Since 1997, Southwestern has established a growing presence in the Permian Basin. At December 31, 2001, Southwestern had proved reserves of 33.5 Bcf of gas and 4,251 MBbls of oil in the basin, or 59.0 Bcfe. The Company successfully completed 19 out of 26 wells drilled in the Permian in 2001, resulting in a success rate of 73%. Southwestern's average working interest in these wells was approximately 43%. Average net daily equivalent production in the basin was 17.0 MMcfe and production costs, including production taxes, averaged $.67 per Mcfe during 2001. In 2001, the Company invested $13.6 million in the Permian, resulting in reserve additions of 5.4 Bcfe for a finding and development cost of $2.52 per Mcfe. Southwestern's three-year average finding and development cost in the Permian is $1.33 per Mcfe and three-year average reserve replacement ratio is 197%.

Southwestern had a meaningful discovery during 2001 at its Roepke prospect in Crane County, Texas. The discovery well, the Cowden Ranch 48 #7, encountered approximately 87 feet of oil-bearing pay in the Upper and Lower Devonian formations. This well, along with two other successful wells on the prospect, added net reserves of 3.3 Bcfe in 2001, and has set up additional development wells planned for 2002.

In late 1999, the Company entered into a joint exploration agreement with Phillips Petroleum to explore for deeper formations under acreage that is held-by-production in Southeast New Mexico. This initial joint venture agreement spawned the development of two more joint exploration agreements that were consummated in late 2000, one with Energen Resources and a second agreement with Phillips. In total, these agreements provide the Company access to an additional 98,700 gross acres to pursue drilling opportunities. Under the agreements, Phillips and Energen have a deferred election at casing point, allowing them to retain a pre-specified working interest share. These agreements have terms ranging from 12 to 21 months, with continuous drilling options thereafter. To date, the Company has successfully drilled 18 out of 21 wells under these joint ventures and four wells are scheduled to be drilled under the agreements in 2002.

The Company plans to continue to pursue its strategy of medium-risk exploration and exploitation in the Permian Basin, albeit at a slower pace. Southwestern plans to invest approximately $8.0 million in the Permian in 2002, which includes drilling up to 14 wells.

Louisiana. South Louisiana continues to be the main focus area of the Company's exploration activities. At December 31, 2001, Southwestern had proved reserves of 34.8 Bcf of gas and 1,261 MBbls of oil in the state, representing 11% of the Company's total reserves on a gas equivalent basis. Average net daily production in this area was 13.2 MMcfe and production costs (including production taxes) averaged $.58 per Mcfe during 2001. The Company invested $24.6 million in the area in 2001 and added 14.3 Bcfe of proved reserves for a finding and development cost of $1.72 per Mcfe. Southwestern's three-year average finding and development cost in Louisiana is $1.65 per Mcfe and its three-year reserve replacement ratio is 484%.

Southwestern's exploration success continued in 2001 with three meaningful discoveries in South Louisiana. Since the first exploration discovery at the Company's Gloria prospect in December 1999, Southwestern has posted an impressive track record in the area with six successful wells out of the last nine drilled in South Louisiana.

In January 2001, Southwestern announced a discovery at its Malone prospect, located five miles south of the Company's Gloria discovery in Assumption Parish. The discovery well SL 16626 #1 encountered approximately 260 feet of gas pay in five separate productive sands within the Miocene formation. After drilling the initial discovery well, Southwestern immediately drilled an offset development well on the prospect that reached total depth in February 2001. Both wells are producing at a combined gross rate of 27.0 MMcf/d and 525 barrels of oil per day (Bopd). Southwestern is the operator of the wells and holds a 33% working interest and a 24.3% net revenue interest in the prospect.

After drilling dry holes at its Whitehorse and Mahone prospects, the Company made another gas discovery in its Eden 3-D project area. The Mire #1 well on the Company's Horeb prospect in Acadia Parish penetrated 50 feet of pay in the Nonion Struma sand at approximately 12,100 feet. This well was placed on production in November 2001 and is currently producing 12.6 MMcf/d and 160 Bopd. Southwestern operates the Mire well with a 21.5% working interest and a 16.4% net revenue interest.

In December 2001, the Company announced a discovery at its Crowne Prospect located in Cameron Parish, Louisiana. The Miami Corporation #27-1 well encountered 75 feet of pay in the targeted Planulina objective. The well was placed on production in February 2002 at 10.0 MMcf/d and 35 Bopd. Southwestern has spud a second well, the Miami Corporation #34-2, to further delineate and develop the reservoir. Southwestern is the operator of these wells with a 40% working interest and a 28.8% net revenue interest.

In February 2002, the Company announced that it had reached total depth on the Raymond Egle #1, a development well on its North Grosbec discovery. After overcoming significant mechanical problems during the drilling of this well, it was placed on production at 20.0 MMcf/d and 800 Bopd. The discovery well, the Brownell-Kidd #1, continues to deliver at high rates since being placed on production in May 2000 and is currently producing at 15.0 MMcf/d and 550 Bopd. These wells are operated by Petro-Hunt, L.L.C., and Southwestern holds a 25% working interest and a 17.4% net revenue interest in the prospect.

The Company has an extensive inventory of 3-D seismic data covering over 1,470-square miles in Louisiana. From this extensive 3-D database, Southwestern has internally generated an inventory of exploration prospects. The Company also continues to gain exposure to additional 3-D seismic data for future drilling opportunities, including a new 3-D shoot currently underway covering approximately 140-square miles in a highly prospective region in St. Martin and St. Mary Parishes. Southwestern is the operator of the new project with a 40% working interest. The seismic data is expected to be delivered in the third quarter of 2002. In 2002, the Company plans to invest approximately $22.7 million in the Gulf Coast region and drill up to eight exploration wells.

Acquisitions

In 2001, Southwestern purchased proved reserves of 4.5 Bcfe for $6.5 million, or $1.46 per Mcfe. Included were overriding royalty interests in the Arkoma Basin of 2.2 Bcfe, and 1.9 Bcfe of additional working interest in the Company's Overton Field.

In April 2000, the Company purchased the Overton Field in Smith County, Texas, from Total Fina Elf for $6.1 million. Proved developed producing reserves associated with the purchase were 7.5 Bcfe, for a purchase price of $.81 per Mcfe. The purchase included 16 active gas wells in 13 spacing units, 8,800 contiguous acres in established units and 2,000 additional undeveloped acres outside the units. As discussed previously, Southwestern believes the Overton Field contains significant development potential.

In 1999, the Company purchased producing properties in the Permian Basin with estimated proved reserves of 9.4 Bcf of gas and 576 MBbls of oil, or 12.9 Bcfe. The properties were purchased from Petro-Quest Exploration, a privately held company headquartered in Midland, Texas, for $9.4 million. The Company did not make any producing property acquisitions in 1998 or 1997. In 1996, the Company acquired approximately 32.7 Bcf of gas and 6,350 MBbls of oil located in Texas and Oklahoma for $45.8 million. The Company's current strategy is to pursue selective acquisitions where it sees further potential and that complement its existing operations.

Capital Spending

Southwestern invested a total of $99.0 million in its exploration and production program during 2001, including $13.5 million funded by the owner of the minority interest in the Overton partnership. Southwestern participated in drilling 101 wells during 2001, of which 80 were successful, 19 were dry and two were still in progress at year-end. The Company's investments were balanced between its core areas of operations, with approximately $28.6 million invested in the Arkoma Basin, $30.9 million at Overton Field in East Texas, $13.6 million in the Permian Basin, and $24.6 million in South Louisiana. Approximately $20.6 million was invested in exploratory tests, $57.2 million in development drilling and workovers, $4.2 million for the acquisition of leasehold and seismic data, $6.5 million for producing property acquisitions and $10.5 million in capitalized interest and expenses and other technology-related expenditures.

In 2002, the Company's planned capital budget for exploration and production is $61.3 million, and a large percentage of this capital, approximately 67%, is allocated to drilling. As in 2001, the Company's investments will again be balanced between its core areas of operations, with approximately 50% of the Company's capital allocated to lower-risk development drilling activities in the Arkoma Basin ($18.5 million) and East Texas ($12.1 million). The remainder of Southwestern's capital will be allocated to medium-risk exploration and exploitation in the Permian Basin ($8.0 million) and to high-potential exploration in the Gulf Coast ($22.7 million). Of the $61.3 million capital budget, approximately $11.4 million is allocated to exploration wells, $29.9 million to development drilling, $4.3 million for land and leasehold acquisition, $3.9 million for seismic expenditures, and $11.8 million in capitalized interest and expenses and technology-related items. Although no capital was budgeted for acquisitions in 2002, the Company will continue to seek producing property transactions in its core producing areas that would complement its overall strategy. The Company expects to maintain its capital investments within the limits of internally generated cash flow, and will adjust its capital program accordingly.

Sales and Major Customers

Daily natural gas equivalent production averaged 109.0 MMcfe in 2001, compared to 97.7 MMcfe in 2000 and 90.2 MMcfe in 1999. The Company's gas production was 35.5 Bcf in 2001, compared to 31.6 Bcf in 2000 and 29.4 Bcf in 1999. The Company also produced 719,000 barrels of oil in 2001, compared to 676,000 barrels of oil in 2000 and 578,000 barrels in 1999. Southwestern is targeting its production in 2002 to be approximately 42 Bcfe.

The Company realized an average wellhead price of $3.85 per Mcf for its natural gas production in 2001, compared to $2.88 per Mcf in 2000 and $2.21 per Mcf in 1999. The Company's average oil price realized was $23.55 per barrel in 2001, compared to $22.99 per barrel in 2000 and $17.11 per barrel in 1999.

Southwestern's gas sales to unaffiliated purchasers were 30.4 Bcf in 2001, compared to 23.8 Bcf in 2000 and 21.2 Bcf in 1999. All of the Company's oil production is sold to unaffiliated purchasers. This gas and oil production is sold under contracts which reflect current short-term prices and which are subject to seasonal price swings. These combined gas and oil sales accounted for 83% of total exploration and production revenues in 2001, 76% in 2000 and 69% in 1999.

Southwestern's largest single customer for sales of its gas production is the Company's utility subsidiary, Arkansas Western Gas Company (Arkansas Western). These sales are made by SEECO, Inc. (SEECO) primarily under contracts obtained under a competitive bidding process. See "Natural Gas Distribution – Gas Purchases and Supply" below for further discussion of these contracts. Sales to Arkansas Western accounted for approximately 17% of total exploration and production revenues in 2001, 24% in 2000 and 31% in 1999. SEECO's sales to Arkansas Western were 5.1 Bcf in 2001, compared to 7.8 Bcf in 2000 and 8.2 Bcf in 1999. The decrease in sales in 2001 was primarily caused by Arkansas Western's reduced supply requirements due to warmer weather and the sale of the utility's Missouri gas distribution properties in May 2000. Weather in 2001, as measured in degree days, was 9% warmer than both normal and the prior year for Arkansas Western's service territory. Weather was normal in 2000 and 21% colder than 1999; however, sales to Arkansas Western decreased in 2000 due to the sale of the utility's Missouri properties. SEECO's gas production provided approximately 33% of the utility's requirements in 2001, 42% in 2000 and 41% in 1999. SEECO also owns an unregulated natural gas storage facility that has historically been utilized to help meet its peak seasonal sales commitments. The storage facility is connected to Arkansas Western's distribution system.

Future sales to Arkansas Western's gas distribution systems will be dependent upon the Company's success in obtaining gas supply contracts with the utility systems. In the future, the Company's subsidiaries will continue to bid to obtain these gas supply contracts, although there is no assurance that it will be successful. If successful, the Company cannot predict the amount of premium that would be associated with the new contracts. Southwestern expects future increases in its gas production to come primarily from sales to unaffiliated purchasers. The Company is unable to predict changes in the market demand and price for natural gas, including changes which may be induced by the effects of weather on demand of both affiliated and unaffiliated customers for the Company's production. Additionally, the Company holds a large amount of undeveloped leasehold acreage and producing acreage, and has an inventory of drilling leads, prospects and seismic data that will continue to be evaluated and developed in the future. The Company's exploration programs have been directed primarily toward natural gas in recent years.

The Company periodically enters into hedging activities with respect to a portion of its projected crude oil and natural gas production through a variety of financial arrangements intended to support oil and gas prices at targeted levels and to minimize the impact of price fluctuations. The Company's policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings. At December 31, 2001, the Company had hedges in place on 32.3 Bcf of future gas production. Subsequent to December 31, 2001 and prior to March 13, 2002, the Company hedged 4.0 Bcf of 2002 gas production under costless collars with floor prices ranging from $2.25 to $2.50 per Mcf and ceiling prices ranging from $3.00 to $3.75 per Mcf, and entered into a collar on 4.0 Bcf of 2003 gas production with a $3.00 per Mcf floor and a $4.75 per Mcf ceiling. Fixed price swaps on 2.5 Bcf of 2002 gas production have a weighted average fixed price receipt of $2.61 per Mcf. The Company also hedged 277,500 barrels of 2002 oil production at a fixed West Texas Intermediate crude price of $20.07 per barrel. The Company currently has hedges in place on approximately 65% of its targeted 2002 gas production and approximately 40% of its 2002 targeted oil production. See Item 7A of this Form 10-K, "Quantitative and Qualitative Disclosures About Market Risk," for further information regarding the Company's hedge position at December 31, 2001.

Disregarding the impact of hedges, the Company expects the average price it receives for its gas production to be approximately $.05 to $.10 per Mcf lower than average spot market prices, as market differentials that reduce the average prices received are partially offset by demand charges it receives under the contracts covering its intersegment sales to Arkansas Western. Disregarding the impact of hedges, the Company expects the average price it receives for its oil production to be approximately $1.00 per barrel lower than average spot market prices, as market differentials reduce the average prices received.

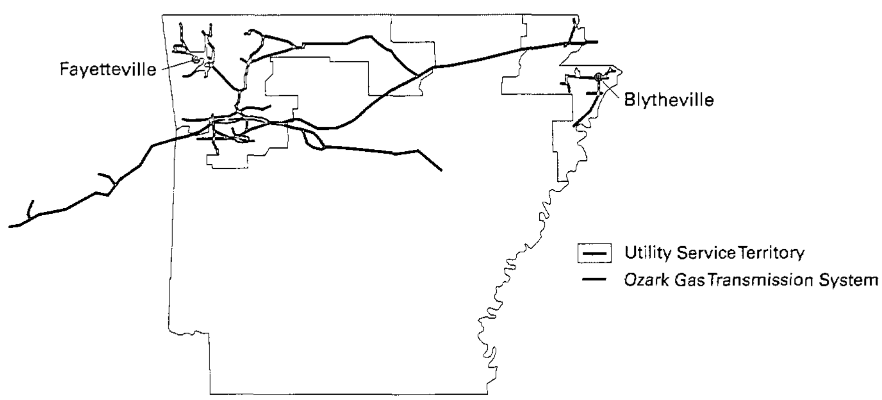
Competition

All phases of the gas and oil industry are highly competitive. Southwestern competes in the acquisition of properties, the search for and development of reserves, the production and sale of gas and oil and the securing of the labor and equipment required to conduct operations. Southwestern's competitors include major gas and oil companies, other independent gas and oil concerns and individual producers and operators. Many of these competitors have financial and other resources that substantially exceed those available to Southwestern. Gas and oil producers also compete with other industries that supply energy and fuel.

Competition in the state of Arkansas has increased in recent years, due largely to the development of improved access to interstate pipelines. Due to the Company's significant leasehold acreage position in Arkansas and its long-time presence and reputation in this area, the Company believes it will continue to be successful in acquiring new leases in Arkansas. While improved intrastate and interstate pipeline transportation in Arkansas should increase the Company's access to markets for its gas production, these markets will generally be served by a number of other suppliers. Thus, the Company will encounter competition that may affect both the price it receives and contract terms it must offer. Outside Arkansas, the Company is less established and faces competition from a larger number of other producers. The Company has in recent years been successful in building its inventory of undeveloped leases and obtaining participating interests in drilling prospects in Oklahoma, Texas, New Mexico and Louisiana.

NATURAL GAS DISTRIBUTION

The Company's subsidiary, Arkansas Western Gas Company, operates integrated natural gas distribution systems concentrated primarily in North Arkansas. The Arkansas Public Service Commission (APSC) regulates the Company's utility rates and operations. Arkansas Western serves approximately 136,000 customers and obtains a substantial portion of the gas they consume through its Arkoma Basin gathering facilities.



On May 31, 2000, the Company completed the sale of its Missouri gas distribution assets for $32.0 million. The sale resulted in a pretax gain of approximately $3.2 million and proceeds from the sale were used to pay down debt. The gas distribution statistics discussed below include the results from the Company's Missouri utility operations through May 2000.

In June 2000, Southwestern announced it would pursue the sale of its utility operations in Arkansas to fund a $109.3 million judgment against the Company (Hales judgment). The Company hired Morgan Stanley Dean Witter as its investment advisor to manage the sale process and the Company received several serious expressions of interest from bona fide parties. However, the Company did not receive an offer that it believed reflected the true value of the utility system. Southwestern plans to operate the Arkansas utility properties as a continuing part of its business.

Gas Purchases and Supply

Arkansas Western purchases its system gas supply through a competitive bidding process implemented in October 1998, and directly at the wellhead under long-term contracts with flexible pricing provisions. Bid requests under the bidding process included replacement of the gas supply and no-notice service previously provided by a long-term gas supply contract between Arkansas Western and SEECO. In the initial 1998 bid, SEECO, along with the Company's marketing subsidiary, successfully bid on five of seven gas supply packages with prices based on the Reliant East Index plus a demand charge. Based on normal weather patterns, the volumes of gas projected to be supplied under these contracts were approximately equal to the historical annual volumes purchased under the expired long-term contract. However, under the new contracts, SEECO supplied most of Arkansas Western's no-notice service and less of its routine base requirements than it had under the previous contract. As a result, during periods of warmer weather, lower total gas volumes would be purchased by Arkansas Western than compared to periods of normal or colder weather. All of the bid packages originally secured by the Company's subsidiaries in 1998 have now expired. During the third quarter of 2001, SEECO successfully bid on gas supply packages representing approximately half of the requirements for Arkansas Western for 2002. SEECO was unsuccessful in bidding on a no-notice gas supply package that it previously held that generated a significant portion of the demand charges it received on affiliated sales.

Arkansas Western also purchases gas for its system supply from unaffiliated suppliers accessed by interstate pipelines. These purchases are under firm contracts with terms between one and two years. The rates charged by most suppliers include demand components to ensure availability of gas supply and a commodity component which is based on monthly indexed market prices. The pipeline transportation rates include demand charges to reserve pipeline capacity and commodity charges based on volumes transported. A portion of the utility's gas purchases are under take-or-pay contracts. Currently, Arkansas Western believes that it does not have a significant exposure to take-or-pay liabilities resulting from these contracts and expects to be able to continue to satisfactorily manage these contracts.

Arkansas Western has a regulated natural gas storage facility connected to its distribution system in Northwest Arkansas that it utilizes to help meet its peak seasonal demands. The utility also owns a liquefied natural gas facility and contracts with an interstate pipeline for additional storage capacity to serve its system in the northeastern part of the state. These contracts involve demand charges based on the maximum deliverability, capacity charges based on the maximum storage quantity, and charges for the quantities injected and withdrawn.

Arkansas Western has no restriction on adding new residential or commercial customers and will supply new industrial customers that are compatible with the scale of its facilities. Arkansas Western has never denied service to new customers within its service area or experienced curtailments because of supply constraints. Curtailment of large industrial customers occurs only infrequently when extremely cold weather requires that system capacity be dedicated exclusively to human needs customers.

The utility's rate schedules include purchased gas adjustment clauses whereby the actual cost of purchased gas above or below the level included in the base rates is permitted to be billed or is required to be credited to customers. Each month, the difference between actual costs of purchased gas and gas costs recovered from customers is deferred. The deferred differences are billed or credited, as appropriate, to customers in subsequent months.

Markets and Customers

Arkansas Western continues to capitalize on the healthy economies and sustained customer growth found in its Northwest Arkansas service territory. In April 2001, the U.S. Census Bureau named Northwest Arkansas as the 6th fastest growing community in the United States. The area population grew 47.5%, or 4.0% annually, over the past ten years. As home to the largest public corporation in the world, Wal-Mart Stores, Inc., the region has enjoyed significant growth due to its presence in the area. Other corporations such as Tyson Foods and J.B. Hunt Transportation have also contributed to the impressive development of this region of the state. Approximately 85% of Arkansas Western's customers are located in this growing region.

Arkansas Western provides natural gas to approximately 120,000 residential, 16,000 commercial, and 200 industrial customers, while also providing gas transportation services to approximately 60 end-use and off-system customers. Total gas throughput in 2001 was 27.1 Bcf, compared to 33.5 Bcf in 2000 and 36.4 Bcf in 1999. The decrease in 2001 resulted from the loss of throughput associated with the sale of the utility's Missouri assets in May 2000 and warmer weather. In 2000, the loss of throughput associated with the sale of the Missouri assets was partially offset by colder weather. Off-system transportation volumes were 3.1 Bcf in both 2001 and 2000 and 4.8 Bcf in 1999.

Residential and Commercial. Approximately 85% of the utility's revenues are from residential and commercial markets. Residential and commercial customers combined accounted for 54% of total gas throughput for the gas distribution segment in 2001, compared to 55% in 2000 and 51% in 1999. Gas volumes sold to residential customers were 8.4 Bcf in 2001, compared to 10.9 Bcf in 2000 and 10.8 Bcf in 1999. Gas sold to commercial customers totaled 6.1 in 2001 and 7.6 Bcf in 2000 and 1999. The decreases in gas volumes sold in 2001 were due to the sale of the Company's Missouri utility properties and warmer weather. Weather during 2001 was 9% warmer than both normal and the prior year as measured by degree days.

The gas heating load is one of the most significant uses of natural gas and is sensitive to outside temperatures. Sales, therefore, vary throughout the year. Profits, however, have become less sensitive to fluctuations in temperature recently as tariffs implemented in Arkansas contain a weather normalization clause to lessen the impact of revenue increases and decreases which might result from weather variations during the winter heating season.

Industrial and End-use Transportation. Deliveries to Arkansas Western's industrial and transportation customers were 9.5 Bcf in 2001, 11.8 Bcf in 2000 and 13.1 Bcf in 1999. The decrease in deliveries in both 2001 and 2000 were primarily due to the sale of the utility's Missouri properties. No industrial customer accounts for more than 9% of Arkansas Western's total throughput. Arkansas Western offers a transportation service that allows larger business customers to obtain their own gas supplies directly from other suppliers. A total of 54 customers are currently using the transportation service.

Competition

Arkansas Western has experienced a general trend in recent years toward lower rates of usage among its customers, largely as a result of conservation efforts that the Company encourages. Competition is increasingly being experienced from alternative fuels, primarily electricity, fuel oil, and propane. Arkansas Western has historically maintained a substantial price advantage over these fuels for most applications. This has enabled the utility to achieve excellent market penetration levels. However, the high gas prices experienced in the 2000 – 2001 heating season temporarily eroded the price advantage in some markets. Arkansas Western has now regained its price advantage in substantially all markets as gas prices have declined. Arkansas Western also has the ability through its approved tariffs to lower its rates to large customers to be competitive with available alternative fuels or if the threat of bypass exists.

Regulation

Arkansas Western's utility rates and operations are regulated by the APSC. The Company operates through municipal franchises that are perpetual by state law. These franchises, however, are not exclusive within a geographic area. As the regulatory focus of the natural gas industry has shifted from the federal level to the state level, some utilities across the nation have unbundled residential sales services from transportation services in an effort to promote greater competition. Although no such legislation or regulatory directives related to natural gas are presently pending in Arkansas, Arkansas Western is aggressively controlling costs and constantly reviewing issues such as system capacity and reliability, obligation to serve, rate design and stranded or transition costs.

In Arkansas, the state legislature enacted Act 1556 for the deregulation of the retail sale of electricity by 2002. Act 1556 was modified by Act 324 of 2001 delaying the implementation of electric deregulation to not earlier than October 2003 and no later than October 2005. In December 2001, the APSC submitted its annual report to legislature on the development of electric deregulation and recommended that the legislature consider suspending deregulation to the year 2010 or 2012, or repeal Act 1556 (as modified by Act 324). It is unknown what final legislation will be adopted or, if it is adopted, what its final form will be. If electric deregulation occurs in Arkansas, legislative or regulatory precedents may be set that would also affect natural gas utilities in the future. These issues may include further unbundling of services and the regulatory treatment of stranded costs.

Arkansas Western's most recent rate increase was approved in December 1996 for the utility's Northwest region and in December 1997 for its Northeast region. The APSC approved annual rate increases of $5.1 million and $1.2 million, respectively. The December 1996 rate increase order issued by the APSC also provided that Arkansas Western cause to be filed with the APSC an independent study of its procedures for allocating costs between regulated and non-regulated operations, its staffing levels and executive compensation. The independent study was ordered by the APSC to address issues raised by the Office of the Attorney General of the State of Arkansas. The study was conducted in 1999 with a final report issued in December 1999. The report found the Company's costs to be reasonable in all categories.

In May 1999, the Staff of the APSC initiated a proceeding in which it sought an annual reduction of approximately $2.3 million in the rates Arkansas Western charges its customers in Northwest Arkansas. Staff's position was based on various adjustments to the utility's rate base, operating expenses, capital structure and rate of return. A large portion of the proposed reduction was based on a downward adjustment to the utility's current return on equity authorized by the APSC in 1996. During the third quarter of 1999, Arkansas Western reached agreement with the Staff and the APSC to resolve this issue and to close several other open dockets. In the settlement agreement, Arkansas Western agreed to reduce its rates collected from customers on a prospective basis in the amount of $1.4 million annually, effective December 1, 1999. The agreement also includes the resolution of a proceeding initiated in December 1998 by the Staff of the APSC where the Staff had recommended the disallowance of approximately $3.1 million of gas supply costs. As a part of the settlement, this docket was closed with no negative adjustment to the Company.

In February 2001, the APSC approved a 90-day temporary tariff to collect additional gas costs not yet billed to customers through the normal purchased gas adjustment clause in the utility's approved tariffs. Arkansas Western had under-recovered purchased gas costs of $12.9 million in its current assets at December 31, 2000. The amount of under-recovered purchased gas costs increased significantly during January 2001 as a result of rapidly increasing gas costs. The temporary tariff allowed the utility accelerated recovery of the gas costs it had incurred during the 2000 – 2001 winter heating season. At December 31, 2001, Arkansas Western had over-recovered purchased gas costs of $8.2 million, which will be refunded to its customers during 2002.

Gas distribution revenues in future years will be impacted by customer growth and rate increases allowed by the APSC. In recent years, Arkansas Western has experienced customer growth of approximately 2% to 3% annually in its Northwest Arkansas service territory, while it has experienced little or no growth in its service territory in Northeast Arkansas. Based on current economic conditions in its service territories, the Company expects this trend in customer growth to continue.

MARKETING AND TRANSPORTATION

Gas Marketing

Southwestern's gas marketing subsidiary, Southwestern Energy Services Company, was formed in 1996 to better enable the Company to capture downstream opportunities which arise through marketing and transportation activity. Through utilization of Southwestern's existing asset base, its focus is to create and capture value beyond the wellhead.

The Company's marketing operations include the marketing of Southwestern's own gas production and third-party natural gas. Operating income for this segment was $2.7 million in 2001, compared to $2.5 million in 2000 and $2.1 million in 1999. The segment marketed 49.6 Bcf of natural gas in 2001, compared to 59.6 Bcf in 2000 and 63.1 Bcf in 1999. In late 2000, this segment began marketing less third-party natural gas in an effort to reduce its potential credit risk and concentrated more of its efforts on Southwestern's affiliated production. Of the total volumes marketed, purchases from the Company's exploration and production subsidiaries accounted for 66% in 2001, 33% in 2000 and 31% in 1999.

NOARK Partnership

At December 31, 2001, the Company held a 25% general partnership interest in NOARK. The NOARK Pipeline was a 258-mile intrastate natural gas transmission system that extended across northern Arkansas interconnecting with Arkansas Western's gas distribution systems. NOARK Pipeline was completed and placed in service in 1992 and has been operating below capacity and generating losses since it was placed in service.

In January 1998, the Company entered into an agreement with Enogex Inc. (Enogex), a subsidiary of OGE Energy Corp., to expand NOARK Pipeline and provide access to Oklahoma gas supplies through an integration of NOARK Pipeline with the Ozark Gas Transmission System (Ozark). Ozark was a 437-mile interstate pipeline system that began in eastern Oklahoma and terminated in eastern Arkansas. Enogex acquired Ozark and contributed the pipeline system to the NOARK partnership. Enogex also acquired the NOARK partnership interests not held by Southwestern. On July 1, 1998, the Federal Energy Regulatory Commission (FERC) authorized the operation and integration of Ozark and NOARK Pipeline as a single, integrated pipeline. Enogex funded the acquisition of Ozark and the expansion and integration with NOARK Pipeline which resulted in Southwestern's interest in the partnership decreasing from 48% to 25% with Enogex owning a 75% interest. There are also provisions in the agreement with Enogex which allow for future revenue allocations to the Company above its 25% partnership interest if certain minimum throughput and revenue assumptions are not met.

The new integrated system, known as Ozark Pipeline, became operational November 1, 1998, and includes 749 miles of pipeline with a total throughput capacity of 330 MMcf/d. Deliveries are currently being made by the pipeline to portions of Arkansas Western's distribution systems and to the interstate pipelines with which it interconnects. The average daily throughput for the pipeline was 134.1 MMcf/d in 2001, compared to 188.2 MMcf/d in 2000 and 167.5 MMcf/d in 1999. At December 31, 2001, Arkansas Western had transportation contracts with Ozark Pipeline for 66.9 MMcf/d of firm capacity. These contracts expire in 2002 and 2003 and are renewable annually thereafter until terminated with 180 days' notice. The merged pipeline system now has greater access to major gas producing fields in Oklahoma. With access to greater regional production, Southwestern expects the pipeline's additional throughput to create new marketing and transportation opportunities and reduce the losses as experienced on the project in the past. The merged pipeline also provides the Company's utility systems with additional access to gas supply. The Company's share of the pretax loss from operations related to its NOARK investment was $1.5 million in 2001, $1.8 million in 2000 and $2.0 million in 1999.

Competition

The Company's gas marketing activities are in competition with numerous other companies offering the same services, many of which possess larger financial and other resources than those of Southwestern. Some of these competitors are affiliates of companies with extensive pipeline systems that are used for transportation from producers to end-users. Other factors affecting competition are cost and availability of alternative fuels, level of consumer demand, and cost of and proximity to pipelines and other transportation facilities. The Company believes that its ability to effectively compete within the marketing segment in the future depends upon establishing and maintaining strong relationships with producers and end-users.

NOARK Pipeline previously competed with two interstate pipelines, one of which was the Ozark system, to obtain gas supplies for transportation to other markets. Because of the available transportation capacity in the Arkansas portion of the Arkoma Basin, competition had been strong and had resulted in NOARK Pipeline transporting gas for third parties at rates below the maximum tariffs presently allowed. The integration with Ozark provides increased supplies to transport to both local markets and markets served by the three major interstate pipelines that Ozark Pipeline connects with in eastern Arkansas. The Company believes that Ozark Pipeline will provide the additional supplies necessary to compete more effectively for the transportation of natural gas to end-users and markets served by the interstate pipelines.

Regulation

Prior to the integration with Ozark, the operations of NOARK Pipeline were regulated by the APSC. The APSC had established a maximum transportation rate of approximately $.285 per dekatherm. The integration of NOARK Pipeline with Ozark resulted in an interstate pipeline system subject to FERC regulations and FERC approved tariffs. The FERC has set the maximum transportation rate of Ozark Pipeline at $.2867 per dekatherm.

OTHER ITEMS

Environmental Matters

The Company's operations are subject to extensive federal, state and local laws and regulations, including the Comprehensive Environmental Response, Compensation and Liability Act, the Clean Water Act, the Clean Air Act and similar state statutes. These laws and regulations require permits for drilling wells and the maintenance of bonding requirements in order to drill or operate wells and also regulate the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, the prevention and cleanup of pollutants and other matters.

Southwestern maintains insurance against costs of clean-up operations, but is not fully insured against all such risks. Compliance with environmental laws and regulations has had no material effect on Southwestern's capital expenditures, earnings, or competitive position. Although future environmental obligations are not expected to have a material impact on the results of operations or financial condition of the Company, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause the Company to incur material environmental liabilities or costs.

Real Estate Development

Southwestern's wholly owned subsidiary, A. W. Realty Company (AWR), owns an interest in approximately 150 acres of real estate, most of which is undeveloped. AWR's real estate development activities are concentrated on a 130-acre tract of land located near the Company's offices in a growing part of Fayetteville, Arkansas. The Company has owned an interest in this land for many years. The property is zoned for commercial, office, and multi-family residential development. AWR continues to review with a joint venture partner various options for developing this property that would minimize the Company's initial capital expenditures, but still enable it to retain an interest in any appreciation in value. This activity, however, does not represent a significant portion of the Company's business.

Employees

At December 31, 2001, Southwestern had 525 total employees, 31 of whom are represented under a collective bargaining agreement. The Company believes that its relations with its employees are good.

ITEM 2. PROPERTIES

For additional information about the Company's gas and oil operations, refer to Notes 5 and 6 to the financial statements in Item 8 ("Financial Statements and Supplementary Data"). For information concerning capital expenditures, refer to page 41 ("Capital Expenditures" section of Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations"). Also refer to Item 6 ("Selected Financial Data") for information concerning gas and oil produced.

The following table provides information concerning miles of pipe of the Company's gas distribution systems. For a further description of Arkansas Western's properties, see the discussion under Item 1 ("Business").

	Total
Gathering	387
Transmission	984
Distribution	3,756
	5,127

The following information is provided to supplement that presented in Item 8. For a further description of Southwestern's oil and gas properties, see the discussion under Item 1 ("Business").

Leasehold acreage

	Undeveloped		Developed	
	Gross	Net	Gross	Net
Arkoma	126,453	76,051	221,690	161,460
Mid-Continent	6,038	2,884	56,130	3,745
Texas/New Mexico	205,948	78,166	171,915	36,574
Louisiana	107,642	78,161	43,350	9,365
	446,081	235,262	493,085	211,144

Producing wells

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Arkoma	806	402.0	–	–	806	402.0
Mid-Continent	163	111.4	388	78.0	551	189.4
Texas/New Mexico	220	68.8	225	113.4	445	182.2
Louisiana	17	7.8	15	10.6	32	18.4
	1,206	590.0	628	202.0	1,834	792.0

Wells drilled during the year

	Exploratory					
	Productive Wells		Dry Holes		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2001	13.0	6.5	8.0	3.8	21.0	10.3
2000	13.0	4.0	12.0	4.8	25.0	8.8
1999	4.0	1.5	4.0	1.6	8.0	3.1

	Development					
	Productive Wells		Dry Holes		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2001	67.0	29.5	11.0	2.9	78.0	32.4
2000	65.0	21.9	14.0	6.3	79.0	28.2
1999	47.0	18.3	15.0	6.1	62.0	24.4

Wells in progress as of December 31, 2001

	Gross	Net
Exploratory	–	–
Development	2.0	0.9
Total	2.0	0.9

In December 2001, the Company announced that the Miami Corporation #27-1 well at its Crowne prospect in Cameron Parish, Louisiana, encountered approximately 75 feet of net pay in the targeted Planulina objective. In February, the well was placed on production at a rate of 10.0 MMcf/d and 35 Bopd. Southwestern is currently drilling a second well in the prospect to further delineate and develop the reservoir. Southwestern is the operator of these wells with a 40% working interest.

During 2001, Southwestern was required to file Form 23, "Annual Survey of Domestic Oil and Gas Reserves," with the Department of Energy. The basis for reporting reserves on Form 23 is not comparable to the reserve data included in Note 6 to the financial statements in the 2001 Annual Report to Shareholders. The primary differences are that Form 23 reports gross reserves, including the royalty owners' share, and includes reserves for only those properties where the Company is the operator.

ITEM 3. LEGAL PROCEEDINGS

The Company recently settled litigation, subject to court approval, in a case filed against the Company and two of its subsidiaries in a state court in Sebastian County, Arkansas related to the Company's Stockton Gas Storage Facility in Franklin County, Arkansas (the "Stockton Storage Facility"). As previously disclosed, this class action suit was filed on August 25, 2000 on behalf of a class of plaintiffs comprised of all surface owners, mineral owners, royalty owners and overriding royalty owners in the Stockton Storage Facility. The plaintiffs alleged various wrongful, intentional and fraudulent acts relating to the operation of the storage pool beginning in 1968 and continuing to the present and claimed ownership rights in the gas that the Company has stored in the storage pool in an amount in excess of $5 million in actual damages, interest, attorney's fees and punitive damages. Under the terms of the settlement, the Company has agreed to pay the plaintiffs a cash settlement amount and enter into new gas storage agreements at rental rates commensurate with current market rates. The settlement of this litigation did not have a material impact on the Company's results of operations for 2001.

The Company is subject to laws and regulations relating to the protection of the environment. The Company's policy is to accrue environmental and cleanup related costs of a non-capital nature when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on the financial position or reported results of operations of the Company.

The Company is subject to other litigation and claims that have arisen in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such litigation and claims will not have a material effect on the results of operations or the financial position of the Company.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted during the fourth quarter of the fiscal year ended December 31, 2001, to a vote of security holders, through the solicitation of proxies or otherwise.

Executive Officers of the Registrant

Name	Officer Position	Age	Years Served as Officer
Harold M. Korell	President and Chief Executive Officer and Director	57	5
Greg D. Kerley	Executive Vice President and Chief Financial Officer	46	12
Richard F. Lane	Executive Vice President, Southwestern Energy Production Company and SEECO, Inc.	44	3
Mark K. Boling	Senior Vice President, General Counsel and Secretary	44	–
Charles V. Stevens	Senior Vice President, Arkansas Western Gas Company	52	13

Mr. Korell has served as President since October 1998 and assumed the position of Chief Executive Officer on January 1, 1999. He joined the Company in 1997 as Executive Vice President and Chief Operating Officer. From 1992 to 1997, he was employed by American Exploration Company where he was most recently Senior Vice President - Operations. From 1990 to 1992, he was Executive Vice President of McCormick Resources and from 1973 to 1989, he held various positions with Tenneco Oil Company, including Vice President, Production.

Mr. Kerley was appointed to his present position in December 1999. Previously, he served as Senior Vice President and Chief Financial Officer from 1998 to 1999, Senior Vice President – Treasurer and Secretary from 1997 to 1998, Vice President – Treasurer and Secretary from 1992 to 1997, and Controller from 1990 to 1992. Mr. Kerley also served as the Chief Accounting Officer from 1990 to 1998.

Mr. Lane was appointed to his present position in December 2001. Previously, he served as Senior Vice President from February 2001 and Vice President – Exploration from February 1999. Mr. Lane joined the Company in February 1998 as Manager – Exploration. From 1993 to 1998, he was employed by American Exploration Company where he was most recently Offshore Exploration Manager. Previously, he held various managerial and geological positions at FINA, Inc. and Tenneco Oil Company.

Mr. Boling joined the Company in his present position in January 2002. Prior to joining the Company, Mr. Boling had a private law practice in Houston specializing in the oil and gas industry since 1993. Previously, Mr. Boling was a partner with Fulbright and Jaworski L.L.P. where he was employed from 1982 to 1993.

Mr. Stevens has served the Company in his present position since December 1997. Previously, he served as Vice President of Arkansas Western Gas Company from 1988 to 1997.

All officers are elected at the Annual Meeting of the Board of Directors for one-year terms or until their successors are duly elected. There are no arrangements between any officer and any other person pursuant to which he was selected as an officer. There is no family relationship between any of the named executive officers or between any of them and the Company's directors.

Part II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

The Company's common stock is traded on the New York Stock Exchange under the symbol "SWN." At December 31, 2001, the Company had 2,124 shareholders of record. The following prices represent closing market transactions on the New York Stock Exchange.

	Range of Market Prices				Cash Dividends Paid	
Quarter Ended	2001		2000		2001	2000
March 31	$ 11.20	$ 8.76	$ 7.44	$ 5.44	–	$ .06
June 30	$ 16.35	$ 8.77	$ 10.38	$ 6.06	–	$ .06
September 30	$ 13.50	$ 10.45	$ 10.00	$ 6.13	–	–
December 31	$ 13.05	$ 9.51	$ 10.44	$ 7.25	–	–

On June 22, 2000, the Arkansas Supreme Court affirmed a $109.3 million judgment against the Company from a class action lawsuit brought by royalty owners. As a result of the judgment, the Company suspended its quarterly dividend. Dividends totaling $3.0 million were paid during 2000.

ITEM 6. SELECTED FINANCIAL DATA

	2001	2000	1999	1998	1997	1996
FINANCIAL REVIEW (in thousands)						
Operating revenues						
Exploration and production	$ 153,937	$ 110,920	$ 75,039	$ 86,232	$ 100,129	$ 86,978
Gas distribution	147,282	151,234	132,420	134,711	154,155	142,730
Gas marketing and other	190,773	208,196	137,942	97,795	83,511	30,636
Intersegment revenues	(147,065)	(106,467)	(65,005)	(52,433)	(61,606)	(57,004)
	344,927	363,883	280,396	266,305	276,189	203,340
Operating costs and expenses						
Gas purchases – utility	68,161	58,669	45,370	39,863	46,806	42,851
Gas purchases – marketing	68,010	133,221	92,851	73,235	63,054	14,114
Operating and general	64,108	59,790	57,957	61,915	59,167	50,509
Unusual items	–	111,288	–	–	–	–
Depreciation, depletion and amortization	52,899	45,869	41,603	46,917	48,208	42,394
Write-down of oil and gas properties	–	–	–	66,383	–	–
Taxes, other than income taxes	9,080	8,515	6,557	6,943	7,018	5,476
	262,258	417,352	244,338	295,256	224,253	155,344
Operating income (loss)	82,669	(53,469)	36,058	(28,951)	51,936	47,996
Interest expense, net	(23,699)	(23,230)	(17,351)	(17,186)	(16,414)	(13,044)
Other income (expense)	(799)	1,997	(2,331)	(3,956)	(5,017)	(4,015)
Minority interest in partnership	(930)	–	–	–	–	–
Income (loss) before income taxes and extraordinary item	57,241	(74,702)	16,376	(50,093)	30,505	30,937
Income taxes						
Current	–	–	537	(6,029)	(732)	(5,569)
Deferred	21,917	(28,905)	5,912	(13,467)	12,522	17,320
	21,917	(28,905)	6,449	(19,496)	11,790	11,751
Income (loss) before extraordinary item	35,324	(45,797)	9,927	(30,597)	18,715	19,186
Extraordinary item	–	(890)	–	–	–	–
Net income (loss)	$ 35,324	$ (46,687)	$ 9,927	$ (30,597)	$ 18,715	$ 19,186
Cash flow from operations, net of working capital changes (in thousands)	$ 144,583	$ (53,203)[1]	$ 58,131	$ 93,708	$ 79,483	$ 71,830
Return on equity	19.3 %	n/a	5.21 %	n/a	8.45 %	9.23 %
Common Stock Statistics						
Basic earnings (loss) per share	$ 1.40	$ (1.86)	$ .40	$ (1.23)	$ .76	$ .78
Diluted earnings (loss) per share	$ 1.38	$ (1.86)	$ .40	$ (1.23)	$ .76	$ .78
Cash dividends declared and paid per share	–	$ .12	$ .24	$ .24	$ .24	$ .24
Book value per share	$ 7.19	$ 5.61	$ 7.60	$ 7.45	$ 8.92	$ 8.41
Market price at year-end	$ 10.40	$ 10.38	$ 6.56	$ 7.50	$ 12.88	$ 15.13
Number of shareholders of record at year-end	2,124	2,192	2,268	2,333	2,379	2,572
Average diluted shares outstanding	25,601,110	25,043,586	24,947,021	24,882,170	24,777,906	24,788,587

(1) Cash flow from operations, net of working capital changes, for 2000 would have been $58.1 million excluding the effects of unusual and extraordinary items.

	2001	2000	1999	1998	1997	1996
Capitalization (in thousands)						
Total debt, including current portion	$ 350,000	$ 396,000	$ 302,200	$ 283,436	$ 299,543	$ 278,285
Common shareholders' equity	183,086	141,291	190,356	185,856	221,565	207,941
Total capitalization	$ 533,086	$ 537,291	$ 492,556	$ 469,292	$ 521,108	$ 486,226
Total assets	$ 743,123	$ 705,378	$ 671,446	$ 647,620	$ 710,866	$ 660,190
Capitalization ratios:						
Debt	65.7 %	73.70 %	61.35 %	60.27 %	57.23 %	56.96 %
Equity	34.3 %	26.30 %	38.65 %	39.73 %	42.77 %	43.04 %
Capital Expenditures (in millions)						
Exploration and production	$ 99.0	$ 69.2	$ 59.0	$ 52.4	$ 73.5	$ 110.3
Gas distribution	5.3	6.0	7.1	10.1	12.6	12.8
Other '	1.8	.5	.9	1.9	2.7	1.8
	$ 106.1	$ 75.7	$ 67.0	$ 64.4	$ 88.8	$ 124.9
Exploration and Production						
Natural gas:						
Production, Bcf	35.5	31.6	29.4	32.7	33.4	34.8
Average price per Mcf	$ 3.85	$ 2.88	$ 2.21	$ 2.34	$ 2.57	$ 2.26
Oil:						
Production, MBbls	719	676	578	703	749	391
Average price per barrel	$ 23.55	$ 22.99	$ 17.11	$ 13.60	$ 19.02	$ 21.21
Total gas and oil production, Bcfe	39.8	35.7	32.9	36.9	37.9	37.1
Average production (lifting) cost per Mcf equivalent	$ .62	$ .55	$ .44	$ .43	$ .45	$ .29
Proved reserves at year-end:						
Natural gas, Bcf	355.8	331.8	307.5	303.7	291.4	297.5
Oil, MBbls	7,704	8,130	7,859	6,850	7,852	8,238
Total reserves, Bcfe	402.0	380.6	354.7	344.8	338.5	346.9
Gas Distribution(1)						
Sales and transportation volumes, Bcf:						
Residential	8.4	10.9	10.8	11.1	12.6	13.4
Commercial	6.1	7.6	7.6	7.6	8.4	8.8
Industrial	2.5	3.5	3.5	4.2	6.6	7.7
End-use transportation	7.0	8.3	9.6	8.8	6.6	5.5
	24.0	30.3	31.5	31.7	34.2	35.4
Off-system transportation	3.1	3.1	4.8	1.1	2.8	3.6
	27.1	33.4	36.3	32.8	37.0	39.0
Customers at year-end:						
Residential	119,856	119,024	158,606	156,384	154,864	151,880
Commercial	16,177	16,282	21,929	22,229	21,431	20,845
Industrial	209	228	290	303	311	326
	136,242	135,534	180,825	178,916	176,606	173,051
Degree days	3,654	3,994	3,179	3,472	4,131	4,341
Percent of normal	91 %	100 %	79 %	87 %	103 %	108 %

(1) Gas distribution statistics include the operations of the Company's Missouri properties through the sale date of May 31, 2000.

 The right people doing the right things, wisely investing the cash flow from the underlying assets will create value +.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following information should be read in conjunction with the information contained in the financial statements and the notes thereto included in Item 8 of this report and with the discussion below on "Forward-Looking Information."

RESULTS OF OPERATIONS

Southwestern reported record net income of $35.3 million in 2001, or $1.38 per share on a fully diluted basis, compared to a net loss of $46.7 million in 2000, or $1.86 per share, and net income of $9.9 million in 1999, or $.40 per share. The loss for 2000 includes one-time charges for unusual items, including a $109.3 million judgment in the Hales lawsuit and $2.0 million for other litigation, an extraordinary loss on the early retirement of debt, and a $3.2 million gain from the sale of the Company's Missouri utility properties. Exclusive of these one-time charges and the gain on sale, net income for 2000 would have been $20.5 million, or $.82 per share.

Results for both 2001 and 2000 (excluding unusual items) reflect growth in oil and gas production volumes and higher oil and gas prices realized. Results for 1999 were negatively impacted by lower wellhead prices for the Company's oil and gas production and by unseasonably warm weather.

Exploration and Production

The Company's exploration and production segment's revenue, profitability and future rate of growth are substantially dependent upon prevailing prices for natural gas and oil, which are dependent upon numerous factors beyond its control, such as economic, political and regulatory developments and competition from other sources of energy. The energy markets have historically been very volatile, and there can be no assurance that oil and gas prices will not be subject to wide fluctuations in the future.

	2001	2000	1999
Revenues (in thousands)	$ 153,937	$ 110,920	$ 75,039
Operating income (loss) (in thousands)	$ 69,340	$ (70,584)[1]	$ 16,451
Gas production (Bcf)	35.5	31.6	29.4
Oil production (MBbls)	719	676	578
Total production (Bcfe)	39.8	35.7	32.9
Average gas price per Mcf	$ 3.85	$ 2.88	$ 2.21
Average oil price per Bbl	$ 23.55	$ 22.99	$ 17.11
Operating expenses per Mcfe			
Production expenses	$ 0.45	$ 0.40	$ 0.35
Production taxes	$ 0.17	$ 0.15	$ 0.09
General & administrative expenses	$ 0.34	$ 0.32	$ 0.30
Full cost pool amortization	$ 1.14	$ 1.06	$ 1.00

(1) Includes a charge of $109.3 million for the Hales judgment and a charge of $2.0 million related to other litigation.
Excluding these unusual items, operating income for the exploration and production segment would have been $40.7 million for 2000.

Revenues and Operating Income

The Company's exploration and production revenues increased 39% in 2001 and 48% in 2000. The increases were due to increases in production and higher average prices received.

Operating income of the exploration and production segment was $69.3 million in 2001 compared to $40.7 million in 2000, excluding the impact of the Hales judgment and the other unusual items, and $16.5 million in 1999. The increase in 2001 was due to an 11% increase in equivalent oil and gas production and higher oil and gas prices realized, partially offset by increased operating costs and expenses. The increase in 2000 was due to an 8% increase in equivalent oil and gas production and higher oil and gas prices realized, partially offset by increased operating costs and expenses.

Production and Sales

Gas and oil production totaled 39.8 billion cubic feet equivalent (Bcfe) in 2001, 35.7 Bcfe in 2000 and 32.9 Bcfe in 1999. The increase in 2001 production volumes resulted from the Company's continued exploration and development of its South Louisiana properties, the development of its Overton Field in East Texas and increased production in the Arkoma Basin.

The increase in 2000 production volumes resulted from new wells added in 2000 and 1999 in the Company's Permian Basin and South Louisiana operating areas, partially offset by the loss of production from certain wells in the Company's Mid-Continent operating area that were sold at auction during 2000.

Gas sales to unaffiliated purchasers were 30.4 Bcf in 2001, up from 23.8 Bcf in 2000 and 21.2 Bcf in 1999. Sales to unaffiliated purchasers are primarily made under contracts which reflect current short-term prices and which are subject to seasonal price swings. Intersegment sales to the Company's utility subsidiary, Arkansas Western Gas Company (Arkansas Western) were 5.1 Bcf in 2001, 7.8 Bcf in 2000 and 8.2 Bcf in 1999. See "Gas Distribution – Operating Costs and Expenses" below for further discussion of the utility's gas purchases. The decrease in sales in 2001 was caused by Arkansas Western's reduced supply requirements due to warmer weather and the sale of the utility's Missouri gas distribution properties in May 2000. Weather in 2001, as measured in degree days, was 9% warmer than both normal and the prior year in Arkansas Western's service territory. Weather was normal in 2000 and 21% colder than 1999; however, sales to Arkansas Western decreased in 2000 due to the sale of the utility's Missouri properties. The Company's gas production provided approximately 33% of the utility's requirements in 2001, 42% in 2000 and 41% in 1999.

Future sales to Arkansas Western's gas distribution systems will be dependent upon the Company's success in obtaining gas supply contracts with the utility systems. In the future, the Company will continue to bid to obtain these gas supply contracts, although there is no assurance that it will be successful. If successful, the Company cannot predict the amount of premium that would be associated with the new contracts. The Company expects future increases in its gas production to come primarily from sales to unaffiliated purchasers. The Company is unable to predict changes in the market demand and price for natural gas, including changes which may be induced by the effects of weather on demand of both affiliated and unaffiliated customers for the Company's production. Additionally, the Company holds a large amount of undeveloped leasehold acreage and producing acreage, and has an inventory of drilling leads, prospects and seismic data that will continue to be evaluated and developed in the future. The Company's exploration programs have been directed primarily toward natural gas in recent years.

Commodity Prices

The average price realized for the Company's gas production was $3.85 per Mcf in 2001, $2.88 per Mcf in 2000, and $2.21 per Mcf in 1999. The changes in the average price realized primarily reflects changes in average annual spot market prices and the effects of the Company's price hedging activities. The Company's hedging activities lowered the average gas price $.31 per Mcf in 2001, $1.04 per Mcf in 2000, and $.06 per Mcf in 1999. Additionally, the Company has historically received monthly demand charges related to sales made to its utility segment which has increased the Company's average gas price realized.

The Company periodically enters into hedging activities with respect to a portion of its projected crude oil and natural gas production through a variety of financial arrangements intended to support oil and gas prices at targeted levels and to minimize the impact of price fluctuations (see Item 7A of this Form 10-K and Note 8 of the financial statements for additional discussion). The Company's policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings. At December 31, 2001, the Company had hedges in place on 33.0 Bcf of gas. Subsequent to December 31, 2001 and prior to March 13, 2002, the Company hedged an additional 10.5 Bcf of future gas production. There were no hedges in place at December 31, 2001 on the Company's future oil production. Subsequent to December 31, 2001 and prior to March 13, 2002, the Company hedged 277,500 barrels of its 2002 oil production. The Company currently has hedged approximately 65% of its 2002 anticipated gas production level and 40% of its anticipated oil production level.

Disregarding the impact of hedges, the Company expects the average price it receives for its gas production to be approximately $.05 to $.10 per Mcf lower than average spot market prices, as market differentials that reduce the average prices received are partially offset by demand charges it receives under the contracts covering its intersegment sales to the Company's utility systems. Future changes in revenues from sales of the Company's gas production will be dependent upon changes in the market price for gas, access to new markets, maintenance of existing markets, and additions of new gas reserves.

The Company realized an average price of $23.55 per barrel for its oil production for the year ended December 31, 2001, up from $22.99 per barrel for 2000 and $17.11 per barrel for 1999. The Company's hedging activities lowered the average oil price $.03 per barrel in 2001 and $6.39 per barrel in 2000. Hedges had no impact on the average realized oil price in 1999. Disregarding the impact of hedges, the Company expects the average price it receives for its oil production to be approximately $1.00 per barrel lower than average spot market prices, as market differentials reduce the average prices received.

Operating Costs and Expenses

Production expenses per Mcfe for this business segment were $.45 in 2001, compared to $.40 in 2000 and $.35 in 1999. Production taxes per Mcfe were $.17 in 2001, compared to $.15 in 2000 and $.09 in 1999. The increase in unit production expenses in 2001 was due to increased workover expenses and an industry-wide increase in costs related to normal production activities. The increase in unit production expenses in 2000 was due primarily to an increase in workover expenses. The increases in 2001 and 2000 production taxes per Mcfe were due to increased severance and ad valorem taxes that resulted from higher commodity prices. General and administrative expenses per Mcfe were $.34 in 2001, compared to $.32 in 2000 and $.30 in 1999. The increase in general and administrative costs per Mcfe in 2001 was due primarily to increased legal costs related to the resolution of litigation. The increase in general and administrative costs in 2000 as compared to 1999 resulted primarily from increases in incentive compensation pay that is dependent upon the operating results for this segment.

The Company's full cost pool amortization rate averaged $1.14 per Mcfe for 2001, compared to $1.06 in 2000 and $1.00 in 1999. The rate increased in 2001 as compared to 2000 due primarily to negative revisions of proved reserves that resulted from a decline in average gas prices and to a $6.6 million decline in the balance of unevaluated costs excluded from amortization in the full cost pool. The average rate increased in 2000 due primarily to a $9.9 million decline in the balance of unevaluated costs excluded from amortization.

The Company utilizes the full cost method of accounting for costs related to its oil and natural gas properties. Under this method, all such costs (productive and nonproductive) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test, however, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved gas and oil reserves discounted at 10 percent (standardized measure) plus the lower of cost or market value of unproved properties. Any costs in excess of this ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher oil and gas prices may subsequently increase the ceiling. Full cost companies must use the prices in effect at the end of each accounting quarter to calculate the ceiling value of its reserves. At December 31, 2001, 2000 and 1999, the Company's unamortized costs of oil and gas properties did not exceed this ceiling amount. At December 31, 2001, the Company's standardized measure was calculated based upon quoted market prices of $2.65 per Mcf for gas and $19.84 per barrel for oil, adjusted for market differentials. A decline in oil and gas prices from year-end 2001 levels or other factors, without other mitigating circumstances, could cause a future write-down of capitalized costs and a non-cash charge against future earnings.

In 2001, the Company's subsidiary, Southwestern Energy Production Company (SEPCO), formed a limited partnership with an investor to drill and complete the first 14 development wells in SEPCO's Overton Field located in Smith County, Texas. This partnership was created to provide capital necessary to accelerate the field's development. The Overton properties were acquired by SEPCO in April 2000 and have multiple development locations through the downspacing of the existing producing units. Because SEPCO is the sole general partner and owns a majority interest in the partnership, operating and financial results for the partnership are consolidated with the other operations of the Company and the investor's share of the partnership activity is reported as a minority interest item in the financial statements. During 2001, the minority interest owner in the partnership contributed $13.5 million in capital to the limited partnership and received distributions of $1.5 million. The investor's share of 2001 revenues, less operating costs and expenses, was $.9 million.

Inflation impacts the Company by generally increasing its operating costs and the costs of its capital additions. The effects of inflation on the Company's operations prior to 2000 have been minimal due to low inflation rates. However, during both 2001 and 2000, the impact of inflation intensified in certain areas of the Company's exploration and production segment as shortages in drilling rigs, third-party services and qualified labor developed due to an overall increase in the activity level of the domestic oil and gas industry. The Company anticipates that this impact is now decreasing along with the current level of commodity prices.

Gas Distribution

The operating results of the Company's gas distribution segment are highly seasonal. The extent and duration of heating weather also impacts the profitability of this segment, although the Company has a weather normalization clause that lessens the impact of revenue increases and decreases which might result from weather variations during the winter heating season. The gas distribution segment's profitability is also dependent upon the timing and amount of regulatory rate increases that are filed with and approved by the Arkansas Public Service Commission (APSC). For periods subsequent to allowed rate increases, the Company's profitability is impacted by its ability to manage and control this segment's operating costs and expenses.

On May 31, 2000, the Company completed the sale of its Missouri gas distribution assets for $32.0 million. The sale resulted in a pretax gain of approximately $3.2 million and proceeds from the sale were used to pay down debt. As a result of the adverse Hales judgment, the Company's Board of Directors authorized management to pursue the sale of the Company's remaining gas distribution operations. The sale process did not result in an acceptable bid and the Company currently plans to operate these assets as a continuing part of its business.

	2001	2000	1999
	($ in thousands except for Mcf amounts)		
Revenues	$ 147,282	$ 151,234	$ 132,420
Gas purchases	$ 96,058	$ 93,992	$ 68,876
Operating costs and expenses	$ 40,878	$ 42,587	$ 46,357
Operating income	$ 10,346	$ 14,655	$ 17,187
Deliveries (Bcf)			
Sales and end-use transportation	24.0	30.4	31.6
Off-system transportation	3.1	3.1	4.8
Average number of customers	134,041	152,773	177,328
Average sales rate per Mcf	$ 8.26	$ 6.55	$ 5.67
Heating weather – degree days	3,654	3,994	3,179
Percent of normal	91 %	100 %	79 %

Note: Data for 2000 and 1999 includes the operations of the Company's Missouri properties through the sale date of May 31, 2000. Excluding the Missouri operations, operating income would have been $12.6 million in 2000 and $14.6 million in 1999.

Revenues and Operating Income

Gas distribution revenues fluctuate due to the pass-through of gas supply cost changes and the effects of weather. Because of the corresponding changes in purchased gas costs, the revenue effect of the pass-through of gas cost changes has not materially affected net income.

Gas distribution revenues decreased 3% in 2001 and increased 14% in 2000. The decrease in 2001 was due to the loss of revenues resulting from the sale of the utility's Missouri assets and the effects of warmer weather, partially offset by a higher unit sales rate caused by high gas prices. The increase in 2000 was due to a higher sales rate and increased sales volumes caused by colder weather, partially offset by the loss of revenues resulting from the sale of the utility's Missouri assets in May 2000. Weather during 2001 in the utility's service territory was 9% warmer than both normal and the prior year. Weather in 2000 was normal and 21% colder than the prior year.

Operating income for Southwestern's utility systems decreased 29% in 2001 and 15% in 2000. The decrease in 2001 resulted from the full-year impact of the sale of the utility's Missouri assets, the effects of warmer weather that were not fully offset by the Company's weather normalization clause in its tariffs and increased bad debt expense caused by record high natural gas prices experienced in the first part of 2001. The decrease in 2000 resulted from the sale of the Missouri assets and a $1.4 million annual rate reduction that was implemented in December 1999.

Deliveries and Rates

In 2001, Arkansas Western sold 17.0 Bcf to its customers at an average rate of $8.26 per Mcf, compared to 22.1 Bcf at $6.55 per Mcf in 2000 and 21.9 Bcf at $5.67 per Mcf in 1999. Additionally, Arkansas Western transported 7.0 Bcf in 2001, 8.3 Bcf in 2000 and 9.6 Bcf in 1999 for its end-use customers. The decrease in volumes sold and transported in 2001 resulted from the sale of the utility's Missouri properties and warmer weather. The decrease in the combined volumes sold and transported in 2000 resulted from the sale of the Missouri properties, partially offset by increased deliveries due to colder weather. The fluctuations in the average sales rates reflect changes in the average cost of gas purchased for delivery to the Company's customers, which are passed through to customers under automatic adjustment clauses.

Total deliveries to industrial customers of the utility segment, including transportation volumes, were 9.5 Bcf in 2001, 11.8 Bcf in 2000 and 13.1 Bcf in 1999. The decline in deliveries in 2001 resulted from warmer heating weather and the sale of the utility's Missouri assets. In 2000, the decline resulted from the sale of the Missouri assets. Arkansas Western also transported 3.1 Bcf of gas through its gathering system in both 2001 and 2000 for off-system deliveries, all to the Ozark Gas Transmission System, compared to 4.8 Bcf in 1999. The level of off-system deliveries each year generally reflects the changes of on-system demands of the Company's gas distribution systems for the Company's gas production. The average off-system transportation rate was approximately $.13 per Mcf, exclusive of fuel, in 2001 and $.10 per Mcf in 2000 and 1999.

Gas distribution revenues in future years will be impacted by the utility's gas purchase costs, customer growth and rate increases allowed by the APSC. In recent years, Arkansas Western has experienced customer growth of approximately 2% to 3% annually in its Northwest Arkansas service territory, while it has experienced little or no customer growth in its service territory in Northeast Arkansas. Based on current economic conditions in the Company's service territories, the Company expects this trend in customer growth to continue.

Tariffs implemented in Arkansas as a result of rate increases in both 1996 and 1997 contain a weather normalization clause to lessen the impact of revenue increases and decreases which might result from weather variations during the winter heating season. Rate increase requests, which may be filed in the future, will depend on customer growth, increases in operating expenses, and additional investment in property, plant and equipment. See "Regulatory Matters" below for additional discussion.

Operating Costs and Expenses

The changes in purchased gas costs for the gas distribution segment reflect volumes purchased, prices paid for supplies, the mix of purchases from intercompany versus third-party sources and the sale of Missouri assets as discussed above. Other operating costs and expenses of the gas distribution segment decreased in both 2001 and 2000 due primarily to the sale of the utility's Missouri assets. Operating costs in 2001 included increased bad debt expense caused by high natural gas prices.

In October 1998, Arkansas Western instituted a competitive bidding process for its gas supply. These bid requests included replacement of the gas supply and no-notice service previously provided by a long-term gas supply contract between Arkansas Western and one of the Company's exploration and production subsidiaries, SEECO, Inc. (SEECO). In the initial 1998 bid, SEECO, along with the Company's marketing subsidiary, successfully bid on five of seven gas supply packages with prices based on the Reliant East Index plus a demand charge. Based on normal weather patterns, the volumes of gas projected to be supplied under these contracts were approximately equal to the historical annual volumes sold under the expired long-term contract. However, under the new contracts, SEECO supplied most of Arkansas Western's no-notice service and less of its routine base requirements than it had under the previous contract. As a result, during periods of warmer weather, lower total gas volumes would be purchased by Arkansas Western than compared to periods of normal or colder weather. All of the bid packages originally secured by the Company's subsidiaries in 1998 have now expired. During the third quarter of 2001, SEECO successfully bid on gas supply packages representing approximately half of the requirements for Arkansas Western for 2002. SEECO was unsuccessful in bidding on a no-notice gas supply package that it previously held that generated a significant portion of the demand charges it received on affiliated sales. Other purchases by Arkansas Western are made under long-term contracts with flexible pricing provisions.

Inflation impacts the Company's gas distribution segment by generally increasing its operating costs and the costs of its capital additions. The effects of inflation on the utility's operations in recent years have been minimal due to low inflation rates. Additionally, delays inherent in the rate-making process prevent the Company from obtaining immediate recovery of increased operating costs of its gas distribution segment.

Regulatory Matters

Arkansas Western's rates and operations are regulated by the APSC. It operates through municipal franchises that are perpetual by state law, but are not exclusive within a geographic area. Although its rates for gas delivered to its retail customers are not regulated by the Federal Energy Regulatory Commission (FERC), its transmission and gathering pipeline systems are subject to the FERC's regulations concerning open access transportation. As the regulatory focus of the natural gas industry has shifted from the federal level to the state level, some utilities across the nation have unbundled residential sales services from transportation services in an effort to promote greater competition. No such legislation or regulatory directives related to natural gas are presently pending in Arkansas.

In Arkansas, the state legislature enacted Act 1556 for the deregulation of the retail sale of electricity by 2002. Act 1556 was modified by Act 324 of 2001 delaying the implementation of electric deregulation to not earlier than October 2003 and no later than October 2005. In December 2001, the APSC submitted its annual report to the Arkansas legislature on the development of electric deregulation and recommended that the legislature consider suspending deregulation to the year 2010 or 2012, or repeal Act 1556 (as modified by Act 324). It is unknown what final legislation will be adopted or, if it is adopted, what its final form will be. If electric deregulation occurs in Arkansas, legislative or regulatory precedents may be set that would also affect natural gas utilities in the future. These issues may include further unbundling of services and the regulatory treatment of stranded costs.

Arkansas Western has historically maintained a substantial price advantage over electricity for most applications. This has enabled the utility to achieve excellent market penetration levels. However, during 2001 the high gas prices experienced in the 2000 – 2001 heating season temporarily eroded the price advantage. Arkansas Western has now regained its price advantage in substantially all markets as gas prices have declined.

Arkansas Western's most recent rate increase was approved in December 1996 for the utility's Northwest region and in December 1997 for the Northeast region. The APSC approved increases of $5.1 million and $1.2 million, respectively. During 1999, the APSC initiated a proceeding in which it sought a $2.3 million reduction in the rates for the Northwest region.

In late 1999, the APSC and Arkansas Western reached a settlement in which the Northwest region's rates were reduced by $1.4 million. The reduction was primarily due to a downward adjustment to the return on equity that the APSC had established in the 1996 rate case. While Arkansas Western continues to experience customer growth and has aggressively controlled its costs, its return on investment has declined in recent years. The Company anticipates that it will seek rate relief to improve Arkansas Western's profitability by filing a rate increase application with the APSC during 2002.

In February 2001, the APSC approved a 90-day temporary tariff to collect additional gas costs not yet billed to customers through the utility's normal purchased gas adjustment clause in its approved tariffs. The Company had under-recovered purchased gas costs of $12.9 million in current assets at December 31, 2000. The level of under-recovered costs had increased significantly during January 2001 as a result of rapidly increasing gas costs. The temporary tariff allowed the utility accelerated recovery of the gas costs it had incurred during the 2000 – 2001 winter heating season.

In June 2001, the APSC established a set of policy principles for gas procurement for utilities. The APSC intends for these policy principles to guide utilities in their gas purchasing decisions. Utilities are required to take all reasonable and prudent steps necessary to develop a diversified gas supply portfolio. The portfolio should consist of an appropriate combination of different types of gas purchase contracts and/or financial hedging instruments that are designed to yield the optimum balance of reliability, reduced volatility and reasonable price. Utilities will be required to submit on an annual basis their gas supply plan, along with their contracting and/or hedging objectives, to the APSC's General Staff for review and determination as to whether it is consistent with these policy principles. If the plan includes a hedging strategy and it is determined to be consistent with the objectives of the policy principles, utilities will be allowed to flow any hedging gain or loss to customers through the purchased gas adjustment clause. During 2001, Arkansas Western submitted to the General Staff its annual gas supply plan for the 2001 – 2002 heating season and a revision to its purchased gas adjustment clause for the recovery of hedging gains and losses. Arkansas Western's gas supply plan and the revision to its purchased gas adjustment clause were both approved by the APSC.

Arkansas Western also purchases gas from unaffiliated producers under take-or-pay contracts. The Company believes that it does not have a significant exposure to liabilities resulting from these contracts and expects to be able to continue to satisfactorily manage its exposure to take-or-pay liabilities.

In connection with the sale of its Missouri utility operations in 2000, the Company retained responsibility for five unresolved cases pertaining to the Missouri Public Service Commission's (MPSC) annual review of Arkansas Western's gas cost purchasing practices and gas cost recovery. In November 2001, the MPSC approved a stipulation and agreement that settled all five cases. The settlement did not have a material effect on the Company's results of operations.

Marketing and Other

Marketing

	2001	2000	1999
Revenues (in millions)	$ 190.3	$ 207.7	$ 137.5
Operating income (in millions)	$ 2.7	$ 2.5	$ 2.1
Gas volumes marketed (Bcf)	49.6	59.6	63.1

Operating income for the marketing segment was $2.7 million on revenues of $190.3 million in 2001, compared to $2.5 million on revenues of $207.7 million in 2000, and $2.1 million on revenues of $137.5 million in 1999. The Company marketed 49.6 Bcf in 2001, compared to 59.6 Bcf in 2000 and 63.1 Bcf in 1999. The decline in total volumes marketed in 2001 reflects the Company's increased focus on marketing its own production and limiting the marketing of third-party volumes in an effort to reduce its credit risk. Of the total volumes marketed, purchases from the Company's exploration and production subsidiaries accounted for 66% in 2001, 33% in 2000 and 31% in 1999. The Company enters into hedging activities with respect to its gas marketing activities to provide margin protection (see Item 7A of this Form 10-K and Note 8 of the financial statements for additional discussion).

NOARK Partnership

The marketing segment also manages the Company's 25% interest in the NOARK Pipeline System, Limited Partnership (NOARK). The NOARK Pipeline was a 258-mile intrastate gas transmission system that extended across northern Arkansas interconnecting with the Company's distribution systems. The NOARK Pipeline had been operating below capacity and generating losses since it was placed in service in September 1992.

In January 1998, the Company entered into an agreement with Enogex Inc. (Enogex), a subsidiary of OGE Energy Corp., to expand the NOARK system and provide access to Oklahoma gas supplies through an integration of NOARK with the Ozark Gas Transmission System (Ozark). Ozark was a 437-mile interstate pipeline system which began in eastern Oklahoma and terminated in eastern Arkansas. Effective August 1, 1998, Enogex acquired Ozark and contributed the pipeline system to the NOARK partnership. Enogex also acquired the NOARK partnership interests not held by Southwestern. Enogex funded the acquisition of Ozark and the expansion and integration with NOARK, which resulted in Southwestern's interest in the partnership decreasing to 25% (from 48%) with Enogex owning a 75% interest. There are also provisions in the agreement with Enogex which allow for future revenue allocations to the Company above its 25% partnership interest if certain minimum throughput and revenue assumptions are not met.

Ozark Pipeline, the new integrated system, became operational November 1, 1998, and includes 749 miles of pipeline with a total throughput capacity of 330 million cubic feet of gas per day (MMcf/d). Deliveries are currently being made by the integrated pipeline to portions of Arkansas Western's distribution systems, and to the interstate pipelines with which it interconnects. Ozark Pipeline had an average daily throughput of 134.1 MMcf/d in 2001, 188.2 MMcf/d in 2000 and 167.5 MMcf/d in 1999. In 1998, NOARK had an average daily throughput of 27.3 MMcf/d before the integration with Ozark. As a result of a rate case filed in 2000, Ozark Pipeline's maximum transportation rate increased from $.2455 per dekatherm to $.2867 per dekatherm effective November 1, 2000. At December 31, 2001, the Company's gas distribution subsidiary has transportation contracts with Ozark Pipeline for 66.9 MMcf/d of firm capacity. These contracts expire in 2002 and 2003 and are renewable annually thereafter until terminated with 180 days' notice.

The Company's share of the pretax loss from operations included in other income related to its NOARK investment was $1.5 million in 2001, $1.8 million in 2000, and $2.0 million in 1999. The improvements since 1999 result primarily from the ability to collect higher transportation rates on interruptible volumes. The Company believes that it will be able to continue to reduce the losses it has experienced on the NOARK project and expects its investment in NOARK to be realized over the life of the system (see Note 7 of the financial statements for additional discussion).

As further explained in Note 11 of the financial statements, the Company has severally guaranteed the debt service on a portion of NOARK's outstanding debt. The outstanding balance was $73.0 million at December 31, 2001, and the Company's share of the guarantee relates to $43.8 million of that amount. This debt financed a portion of the original cost to construct the NOARK Pipeline.

Other Income, Costs and Expenses

Interest costs, net of capitalization, were up 2% in 2001 and 34% in 2000, both as compared to prior years. A decrease in interest costs in 2001 that resulted from lower average borrowings and a lower average interest rate was slightly more than offset by a lower level of capitalized interest related to the Company's oil and gas properties. The increase in 2000 was caused primarily by higher average borrowings that resulted from payment of the Hales judgment and a lower level of capitalized interest. Interest capitalized decreased 35% in 2001 and 26% in 2000. The reductions in capitalized interest are primarily due to decreases in the level of costs excluded from amortization in the Company's exploration and production segment.

Other income (expense) in 2001 resulted from the Company's share of NOARK's operating loss, as discussed above, offset by interest income in the gas distribution segment related to under-recovered gas purchase costs. The increase in other income in 2000 resulted from the $3.2 million gain on the sale of the Company's Missouri gas distribution assets and gains from the sale of other miscellaneous assets. Other income (expense) in 1999 related primarily to the Company's share of NOARK's operating loss and certain costs incurred related to a judgment bond that the Company was required to post after receiving the initial adverse verdict in the Hales case.

The Hales judgment was the primary cause for the Company's deferred tax benefit of $28.9 million in 2000. Excluding the impact of this change in deferred income taxes, the changes in the provisions for current and deferred income taxes recorded each year result primarily from the level of taxable income, the collection of under-recovered purchased gas costs, abandoned property costs, and the deduction of intangible drilling costs in the year incurred for tax purposes, netted against the turnaround of intangible drilling costs deducted for tax purposes in prior years. Intangible drilling costs are capitalized and amortized over future years for financial reporting purposes under the full cost method of accounting.

LIQUIDITY AND CAPITAL RESOURCES

The Company depends on internally-generated funds and its revolving line of credit discussed under Financing Requirements as its major sources of liquidity. Net cash provided by operating activities was $144.6 million in 2001, compared to cash used in operating activities of $53.2 million in 2000 and cash provided by operating activities of $58.1 million in 1999. The net cash used in operating activities in 2000 was a result of the Hales judgment and the impact of high year-end gas prices on working capital. The primary components of cash generated from operations are net income, depreciation, depletion and amortization, the provision for deferred income taxes and changes in current assets and current liabilities. Net cash from operating activities provided over 100% of the Company's capital requirements for routine capital expenditures, cash dividends, and scheduled debt retirements in 2001 and 89% in 1999.

The Company's cash flow from operating activities is highly dependent upon market prices that the Company receives for its gas and oil production. The price that the Company receives for its production is also influenced by the Company's commodity hedging activities, as more fully discussed in Item 7A of this Form 10-K and Note 8 to the financial statements. Natural gas and oil prices are subject to wide fluctuations and have declined significantly in the first quarter of 2002 as compared to prices received during 2001. The Company expects 2002 cash flow from operating activities to decline from the 2001 level although it is unable to predict with any degree of accuracy the impact of the decline.

Capital Expenditures

Capital expenditures totaled $106.1 million in 2001, $75.7 million in 2000, and $67.0 million in 1999. The Company's exploration and production segment expenditures included acquisitions of interests in oil and gas producing properties totaling $5.8 million in 2001, $6.7 million in 2000 and $9.4 million in 1999. The Company's reported capital investments in 2001 include the gross expenditures in the Overton Field partnership discussed previously. The owner of the minority interest in the Overton partnership funded $13.5 million of the Company's exploration and development expenditures during 2001.

	2001	2000	1999
		(in thousands)	
Exploration and production	$ 98,964	$ 69,211	$ 59,004
Gas distribution	5,347	5,994	7,124
Other	1,749	512	839
	$ 106,060	$ 75,717	$ 66,967

Capital investments planned for 2002 total approximately $68.0 million, consisting of $61.3 million for exploration and production, $5.7 million for gas distribution system improvements and $1.0 million for general purposes. The Company expects that its level of capital investments will be adequate to allow the Company to maintain its present markets, explore and develop its existing gas and oil properties as well as generate new drilling prospects, and finance improvements necessary due to normal customer growth in its gas distribution segment. The Company may adjust its level of future capital investments dependent upon the level of cash flow generated from operations.

Financing Requirements

Southwestern's total debt outstanding was $350.0 million at December 31, 2001. This compares to total debt of $396.0 million at December 31, 2000, including $171.0 million under a short-term credit facility. In 2001, the Company's strong cash flow from operations allowed it to fund its capital program and pay down $46 million of debt. In July 2001, the Company arranged a new unsecured revolving credit facility with a group of banks to replace its existing short-term credit facility that was put in place in July 2000. The new revolving credit facility has a current capacity of $155 million and expires in July 2004. The capacity of the revolving credit facility decreases to $140 million in June 2002 and to $125 million in June 2003. The interest rate on the new facility is calculated based upon the debt rating of the Company. The Company is currently paying 137.5 basis points over the London Interbank Offered Rate (LIBOR). The new credit facility contains covenants which impose certain restrictions on the Company. Under the credit agreement, the Company may not issue total debt in excess of 70% of its total capital, must maintain a certain level of shareholders' equity, and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense at or above a stated ratio. The ratio of EBITDA to interest expense in effect through December 31, 2002 is 3.75. These covenants change over the term of the credit facility and generally become more restrictive. The Company was in compliance with its debt agreements at December 31, 2001. The Company has also entered into interest rate swaps for calendar year 2002 that allow the Company to pay a fixed average interest rate of 4.8% (based upon current rates under the revolving credit facility) on $100 million of its outstanding revolving debt.

In July 2000, the Company replaced its then existing revolving credit facilities that had previously provided the Company access to $80.0 million of variable rate capital with a new credit facility that had a capacity of $180.0 million. This facility was used to fund the Hales judgment of $109.3 million, pay off the existing revolver balance and retire $22.0 million of private placement debt. The credit facility was also used to fund normal working capital needs. The interest rate on the facility was 112.5 basis points over the LIBOR rate and was 7.85% at December 31, 2000. The credit facility had a term of 364 days and expired in July 2001.

In August 2000, the Company retired $22.0 million of 9.36% private placement notes. Certain costs of the redemption were expensed and are classified as an extraordinary loss, net of related income tax effects.

In 1997, the Company issued $60.0 million of 7.625% Medium-Term Notes due 2027 and $40.0 million of 7.21% Medium-Term Notes due 2017. These notes were issued under a supplement to the Company's $250.0 million shelf registration statement filed with the Securities and Exchange Commission in February 1997, for the issuance of up to $125.0 million of Medium-Term Notes. The Company has $25.0 million of capacity remaining under the shelf registration statement. The Company also has $125.0 million of 6.7% Notes due in 2005 that were issued under the shelf registration. The Company's public notes are rated BBB by Standard and Poor's and Baa3 by Moody's.

If the Company were unable to comply with any of the covenants of its various debt agreements, a waiver would have to be requested to avoid a default under the agreements. Further, the Company's public debt could be downgraded by the rating agencies which could increase the cost of funds under its revolving credit facility.

In June 1998, the NOARK partnership issued $80.0 million of 7.15% Notes due 2018. The notes require semi-annual principal payments of $1.0 million that began in December 1998. The Company accounts for its investment in NOARK under the equity method of accounting and does not consolidate the results of NOARK. The Company and the other general partner of NOARK have severally guaranteed the principal and interest payments on the NOARK debt. The Company's share of the several guarantee is 60% and amounted to $43.8 million at December 31, 2001. The Company advanced $1.4 million to NOARK to fund its share of debt service payments in 2001 and advanced $3.3 million in 2000. If NOARK is unable to generate sufficient cash in the future to service its debt and the Company is required to continue contributing cash to fund its debt service guarantee, the Company could be required to record its share of the NOARK debt commitment under current accounting rules.

At the end of 2001, the Company's capital structure consisted of 65.7% debt (excluding the Company's several guarantee of NOARK's obligations) and 34.3% equity, with a ratio of EBITDA to interest expense of 5.69. As part of its strategy to insure cash flow to fund its operations and meet the restrictive covenant tests under its debt agreements, the Company has hedged approximately 65% of its expected 2002 gas production and 40% of its expected 2002 oil production. The Company does not expect to reduce its long-term debt materially in 2002, assuming commodity prices remain at or near current levels and the Company's capital investment plans do not change from current expectations.

Working Capital

The Company maintains access to funds that may be needed to meet seasonal requirements through its credit facility explained above. The Company had positive working capital of $21.7 million at the end of 2001, compared to net negative working capital of $127.0 million at the end of 2000 caused by the short-term revolving credit facility balance of $171.0 million. Current assets decreased by 17% in 2001, while current liabilities (without consideration of short-term debt) increased 4%. The decrease in current assets and the slight increase in current liabilities at December 31, 2001, was due primarily to decreases in accounts receivable, accounts payable and under-recovered purchased gas costs that resulted from extremely high market prices for natural gas at year-end 2000, offset by increases in gas stored underground, over-recovered purchased gas costs, and current assets and liabilities recorded for derivatives at December 31, 2001. At December 31, 2001, Southwestern had over-recovered purchased gas costs of $8.2 million, which will be refunded to its customers during 2002.

FORWARD-LOOKING INFORMATION

All statements, other than historical financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Although the Company believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include, but are not limited to, the timing and extent of changes in commodity prices for gas and oil, the timing and extent of the Company's success in discovering, developing, producing, and estimating reserves, property acquisition or divestiture activities that may occur, the effects of weather and regulation on the Company's gas distribution segment, increased competition, legal and economic factors, governmental regulation, the financial impact of accounting regulations for derivative instruments, changing market conditions, the comparative cost of alternative fuels, conditions in capital markets and changes in interest rates, availability of oil field services, drilling rigs and other equipment, as well as various other factors beyond the Company's control.

ITEM 7.A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISKS

Market risks relating to the Company's operations result primarily from the volatility in commodity prices, basis differentials and interest rates, as well as credit risk concentrations. The Company uses natural gas and crude oil swap agreements and options and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil and in interest rates. The Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price and interest rate risks. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

Credit Risks

The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of customers and their dispersion across geographic areas. No single customer accounts for greater than 3% of accounts receivable. See the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

The following table provides information on the Company's financial instruments that are sensitive to changes in interest rates. The table presents the Company's debt obligations, principal cash flows and related weighted-average interest rates by expected maturity dates. Variable average interest rates reflect the rates in effect at December 31, 2001 for borrowings under the Company's credit facility. The Company's policy is to manage interest rates through use of a combination of fixed and floating rate debt. Interest rate swaps may be used to adjust interest rate exposures when appropriate. The Company has entered into interest rate swaps for the calendar year 2002 that allow the Company to pay a fixed average interest rate of 4.8% (based upon current rates under the revolving credit facility) on $100 million of its outstanding revolving debt.

	Expected Maturity Date							Fair Value
	2002	2003	2004	2005	2006	Thereafter	Total	12/31/01
				($ in millions)				
Fixed Rate	–	–	–	$ 125.0	–	$ 100.0	$ 225.0	$ 231.2
Average Interest Rate	–	–	–	6.70 %	–	7.46 %	7.04 %	
Variable Rate	–	–	$ 125.0	–	–	–	$ 125.0	$ 125.0
Average Interest Rate	–	–	5.47 %	–	–	–	5.47 %	

Commodities Risk

The Company uses over-the-counter natural gas and crude oil swap agreements and options to hedge sales of Company production, to hedge activity in its marketing segment, and to hedge the purchase of gas in its utility segment against the inherent price risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX (New York Mercantile Exchange) futures market. These swaps and options include (1) transactions in which one party will pay a fixed price (or variable price) for a notional quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps), (2) transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps), and (3) the purchase and sale of index-related puts and calls (collars) that provide a "floor" price below which the counterparty pays (production hedge) or receives (gas purchase hedge) funds equal to the amount by which the price of the commodity is below the contracted floor, and a "ceiling" price above which the Company pays to (production hedge) or receives from (gas purchase hedge) the counterparty the amount by which the price of the commodity is above the contracted ceiling.

The primary market risks related to the Company's derivative contracts are the volatility in market prices and basis differentials for natural gas and crude oil. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of the oil that is hedged. Credit risk relates to the risk of loss as a result of non-performance by the Company's counterparties. The counterparties are primarily major investment and commercial banks which management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure the Company has to each counterparty are periodically reviewed to ensure limited credit risk exposure.

The following table provides information about the Company's financial instruments that are sensitive to changes in commodity prices. The table presents the notional amount in Bcf (billion cubic feet) and MBbls (thousand barrels), the weighted average contract prices, and the total dollar contract amount by expected maturity dates. The "Carrying Amount" for the contract amounts is calculated as the contractual payments for the quantity of gas or oil to be exchanged under futures contracts and does not represent amounts recorded in the Company's financial statements. The "Fair Value" represents values for the same contracts using comparable market prices at December 31, 2001. At December 31, 2001, the "Fair Value" exceeded the "Carrying Amount" of these financial instruments by $4.2 million.

	Expected Maturity Date			
	2002		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
PRODUCTION AND MARKETING				
Natural Gas				
Swaps with a fixed-price receipt				
Contract volume (Bcf)	13.4		9.2	
Weighted average price per Mcf	$ 2.88		$ 3.18	
Contract amount (in millions)	$ 38.6	$ 40.2	$ 29.3	$ 29.3
Swaps with a fixed-price payment				
Contract volume (Bcf)	.3		–	
Weighted average price per Mcf	$ 2.96		–	
Contract amount (in millions)	$ .7	$ .6	–	–
Price collars				
Contract volume (Bcf)	6.0		4.1	
Weighted average floor price per Mcf	$ 4.00		$ 3.00	
Contract amount of floor (in millions)	$ 24.0	$ 32.2	$ 12.3	$ 14.2
Weighted average ceiling price per Mcf	$ 4.72		$ 4.65	
Contract amount of ceiling (in millions)	$ 28.3	$ 27.8	$ 19.0	$ 17.9
NATURAL GAS PURCHASES				
Swaps with a fixed-price payment				
Contract volume (Bcf)	3.3		–	
Weighted average price per Mcf	$ 4.20		–	
Contract amount (in millions)	$ 13.9	$ 8.1	–	–

At December 31, 2001, the Company had a single financial instrument that is sensitive to changes in interest rates. This $50 million notional interest rate swap has a fixed rate of 4.33%. Its carrying amount of $2.2 million is calculated as the contractual payments for interest on the notional amount to be exchanged under futures contracts and does not represent amounts recorded in the Company's financial statements. The fair value of $1.2 million represents the value for the same contract using comparable market prices at December 31, 2001. At December 31, 2001, the "Carrying Amount" exceeded the "Fair Value" of this interest rate swap by $1.0 million. Subsequent to December 31, 2001, the Company entered into additional interest rate swaps totaling $50 million that have an average fixed rate of 2.58%.

Subsequent to December 31, 2001 and prior to March 13, 2002, the Company entered into additional derivative contracts to hedge gas and oil production sales and utility gas purchases. Price collar hedges on 4.0 Bcf of 2002 gas production sales have floor prices ranging from $2.25 to $2.50 per Mcf and ceiling prices ranging from $3.00 to $3.75 per Mcf and a collar on 4.0 Bcf of 2003 gas production has a $3.00 per Mcf floor and a $4.75 per Mcf ceiling. Fixed price swaps on gas production sales of 2.5 Bcf in the second quarter of 2002 will yield a weighted average price of $2.61 per Mcf. Natural gas swaps on notional gas purchase volumes of .3 Bcf in 2002 and .7 Bcf in 2003 were executed under which the Company will pay a fixed price of $2.91 per Mcf. Under a crude oil swap the Company will receive a fixed price of $20.07 per barrel on a notional volume of 277,500 barrels.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Management

Management is responsible for the preparation and integrity of the Company's financial statements. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States consistently applied, and necessarily include some amounts that are based on management's best estimates and judgment.

The Company maintains a system of internal accounting and administrative controls and an ongoing program of internal audits that management believes provide reasonable assurance that assets are safeguarded and that transactions are properly recorded and executed in accordance with management's authorization. The Company's financial statements have been audited by its independent public accountants, Arthur Andersen LLP. In accordance with auditing standards generally accepted in the United States, the independent auditors obtained a sufficient understanding of the Company's internal controls to plan their audit and determine the nature, timing, and extent of other tests to be performed.

The Audit Committee of the Board of Directors, composed solely of outside directors, meets with management, internal auditors, and Arthur Andersen LLP to review planned audit scopes and results and to discuss other matters affecting internal accounting controls and financial reporting. The independent auditors have direct access to the Audit Committee and periodically meet with it without management representatives present.

Report of Independent Public Accountants

To the Board of Directors and Shareholders of Southwestern Energy Company:

We have audited the consolidated balance sheets of SOUTHWESTERN ENERGY COMPANY (an Arkansas corporation) AND SUBSIDIARIES as of December 31, 2001 and 2000, and the related consolidated statements of operations, retained earnings, cash flows and comprehensive income (loss) for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Southwestern Energy Company and Subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 8 to the consolidated financial statements, effective January 1, 2001, the Company changed its method of accounting for derivatives to adopt the requirements of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."

ARTHUR ANDERSEN LLP

Tulsa, Oklahoma
February 4, 2002

Statements of Operations

Southwestern Energy Company and Subsidiaries

For the years ended December 31,	2001	2000	1999
		(in thousands, except share/ per share amounts)	
Operating revenues			
Gas sales	$ 248,952	$ 200,269	$ 165,898
Gas marketing	71,839	137,234	96,570
Oil sales	16,932	15,537	9,891
Gas transportation and other	7,204	10,843	8,037
	344,927	363,883	280,396
Operating costs and expenses			
Gas purchases – utility	68,161	58,669	45,370
Gas purchases – marketing	68,010	133,221	92,851
Operating expenses	39,035	34,808	33,783
General and administrative expenses	25,073	24,982	24,174
Unusual items	–	111,288	–
Depreciation, depletion and amortization	52,899	45,869	41,603
Taxes, other than income taxes	9,080	8,515	6,557
	262,258	417,352	244,338
Operating income (loss)	82,669	(53,469)	36,058
Interest expense			
Interest on long-term debt	23,920	24,089	19,735
Other interest charges	1,374	1,588	923
Interest capitalized	(1,595)	(2,447)	(3,307)
	23,699	23,230	17,351
Other income (expense)	(799)	1,997	(2,331)
Income (loss) before income taxes and minority interest	58,171	(74,702)	16,376
Minority interest in partnership	(930)	–	–
Income (loss) before income taxes	57,241	(74,702)	16,376
Provision (benefit) for income taxes			
Current	–	–	537
Deferred	21,917	(28,905)	5,912
	21,917	(28,905)	6,449
Income (loss) before extraordinary item	35,324	(45,797)	9,927
Extraordinary loss due to early retirement of debt (net of $569,000 tax benefit)	–	(890)	–
Net income (loss)	$ 35,324	$ (46,687)	$ 9,927
Basic earnings per share			
Income (loss) before extraordinary item	$ 1.40	$ (1.82)	$ .40
Extraordinary loss due to early retirement of debt (net of $569,000 tax benefit)	–	(.04)	–
Net income (loss)	$ 1.40	$ (1.86)	$ .40
Basic weighted average common shares outstanding	25,198,105	25,043,586	24,941,550
Diluted earnings per share			
Income (loss) before extraordinary item	$ 1.38	$ (1.82)	$ .40
Extraordinary loss due to early retirement of debt (net of $569,000 tax benefit)	–	(.04)	–
Net income (loss)	$ 1.38	$ (1.86)	$ .40
Diluted weighted average common shares outstanding	25,601,110	25,043,586	24,947,021

The accompanying notes are an integral part of the financial statements.

Balance Sheets

Southwestern Energy Company and Subsidiaries

December 31,	2001	2000
	(in thousands)	
ASSETS		
Current assets		
Cash	$ 3,641	$ 2,386
Accounts receivable	42,763	77,041
Inventories, at average cost	26,606	17,000
Under-recovered purchased gas costs	–	12,942
Hedging asset – SFAS No. 133	9,381	–
Regulatory asset – hedges	5,817	–
Other	4,996	3,486
Total current assets	93,204	112,855
Investments	15,538	15,574
Property, plant and equipment, at cost		
Gas and oil properties, using the full cost method, including $21,102,000 in 2001 and $27,692,000 in 2000 excluded from amortization	970,680	872,023
Gas distribution systems	192,784	190,893
Gas in underground storage	32,046	27,867
Other	30,110	27,940
	1,225,620	1,118,723
Less: Accumulated depreciation, depletion and amortization	605,790	554,616
	619,830	564,107
Other assets	14,551	12,842
	$ 743,123	$ 705,378
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term debt	$ –	$ 171,000
Accounts payable	41,644	54,304
Taxes payable	4,400	4,346
Interest payable	2,653	2,806
Customer deposits	4,845	4,799
Hedging liability – SFAS No. 133	6,990	–
Over-recovered purchased gas costs	8,184	–
Other	2,752	2,629
Total current liabilities	71,468	239,884
Long-term debt	350,000	225,000
Other liabilities		
Deferred income taxes	122,381	97,431
Other	3,187	1,772
	125,568	99,203
Commitments and contingencies		
Minority interest in partnership	13,001	–
Shareholders' equity		
Common stock, $.10 par value; authorized 75,000,000 shares, issued 27,738,084 shares	2,774	2,774
Additional paid-in capital	19,764	20,220
Retained earnings, per accompanying statements	183,677	148,353
Accumulated other comprehensive income	5,763	–
	211,978	171,347
Less: Common stock in treasury, at cost, 2,261,766 shares in 2001 and 2,556,908 shares in 2000	25,196	28,485
Unamortized cost of restricted shares issued under stock incentive plan, 416,537 shares in 2001 and 241,452 shares in 2000	3,696	1,571
	183,086	141,291
	$ 743,123	$ 705,378

The accompanying notes are an integral part of the financial statements.

Statements of Cash Flows

Southwestern Energy Company and Subsidiaries

For the years ended December 31,	2001	2000	1999
		(in thousands)	
Cash flows from operating activities			
Net income (loss)	$ 35,324	$ (46,687)	$ 9,927
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	54,505	47,227	42,971
Deferred income taxes	21,917	(28,905)	5,912
Equity in loss of NOARK partnership	1,484	1,767	2,008
Gain on sale of Missouri utility assets	–	(3,209)	–
Extraordinary loss due to early retirement of debt (net of tax)	–	890	–
Minority interest in partnership	(533)	–	–
Change in assets and liabilities:			
Accounts receivable	34,278	(36,693)	(2,684)
Income taxes receivable	–	85	1,658
Under/over-recovered purchased gas costs	21,126	(14,104)	(273)
Inventories	(9,606)	2,290	1,292
Accounts payable	(12,660)	22,156	(4,711)
Other current assets and liabilities	(1,252)	1,980	2,031
Net cash provided by (used in) operating activities	144,583	(53,203)	58,131
Cash flows from investing activities			
Capital expenditures	(106,060)	(75,717)	(66,967)
Sale of Missouri utility assets	–	32,000	–
Sale of oil and gas properties	–	13,651	–
Investment in NOARK partnership	(1,449)	(3,250)	(2,273)
(Increase) decrease in gas stored underground	(4,179)	845	(4,433)
Other items	826	(1,066)	2,380
Net cash used in investing activities	(110,862)	(33,537)	(71,293)
Cash flows from financing activities			
Net increase (decrease) in revolving debt and short-term note	(46,000)	115,800	20,300
Retirement of notes and payments on long-term debt	–	(24,910)	(1,535)
Contribution from minority interest owner in partnership	13,534	–	–
Dividends paid	–	(3,004)	(5,985)
Net cash provided by (used in) financing activities	(32,466)	87,886	12,780
Increase (decrease) in cash	1,255	1,146	(382)
Cash at beginning of year	2,386	1,240	1,622
Cash at end of year	$ 3,641	$ 2,386	$ 1,240

The accompanying notes are an integral part of the financial statements.

Statements of Retained Earnings

Southwestern Energy Company and Subsidiaries

For the years ended December 31,	2001	2000	1999
		(in thousands)	
Retained earnings, beginning of year	$ 148,353	$ 198,044	$ 194,102
Net income (loss)	35,324	(46,687)	9,927
Cash dividends declared ($.12 per share in 2000, $.24 per share in 1999)	–	(3,004)	(5,985)
Retained earnings, end of year	$ 183,677	$ 148,353	$ 198,044

Statements of Comprehensive Income (Loss)

Southwestern Energy Company and Subsidiaries

For the years ended December 31,	2001	2000	1999
		(in thousands)	
Net income (loss)	$ 35,324	$ (46,687)	$ 9,927
Other comprehensive income:			
Transition adjustment from adoption of SFAS No. 133	(36,963)	–	–
Unrealized gain on derivative instruments	19,852	–	–
Comprehensive income (loss)	$ 18,213	$ (46,687)	$ 9,927
Reconciliation of accumulated other comprehensive income (loss):			
Balance, beginning of year	$ –	$ –	$ –
Transition adjustment from adoption of SFAS No. 133	(36,963)	–	–
Current period reclassification to earnings	22,874	–	–
Current period change in derivative instruments	19,852	–	–
Balance, end of year	$ 5,763	$ –	$ –

The accompanying notes are an integral part of the financial statements.

Notes to Financial Statements

Southwestern Energy Company and Subsidiaries
December 31, 2001, 2000 and 1999

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations and Consolidation

Southwestern Energy Company (Southwestern or the Company) is an integrated energy company primarily focused on natural gas. Through its wholly-owned subsidiaries, the Company is engaged in oil and gas exploration and production, natural gas gathering, transmission and marketing, and natural gas distribution. Southwestern's exploration and production activities are concentrated in Arkansas, Louisiana, Texas, New Mexico and Oklahoma. The gas distribution segment operates in northern Arkansas and, depending upon weather conditions and current supply contracts, can obtain approximately 50% of its gas supply from one of the Company's exploration and production subsidiaries. The customers of the gas distribution segment consist of residential, commercial and industrial users of natural gas. Southwestern's marketing and transportation business is concentrated in its core areas of operations.

On May 31, 2000, the Company completed the sale of its Missouri gas distribution assets for $32.0 million resulting in a pretax gain of approximately $3.2 million. Proceeds from the sale of the Missouri assets were used to reduce the Company's outstanding debt. As a result of the adverse Hales judgment in June 2000, the Company's Board of Directors authorized management to pursue the sale of the Company's remaining gas distribution assets. The sale process did not result in an acceptable bid. The Company currently plans to operate these assets as a continuing part of its business.

The consolidated financial statements include the accounts of Southwestern Energy Company and its wholly-owned subsidiaries, Southwestern Energy Production Company (SEPCO), SEECO, Inc., Arkansas Western Gas Company, Southwestern Energy Services Company, Diamond "M" Production Company, Southwestern Energy Pipeline Company, and A.W. Realty Company. The consolidated financial statements also include the results for a limited partnership, Overton Partners, L.P., in which SEPCO is the sole general partner. All significant intercompany accounts and transactions have been eliminated. The Company accounts for its general partnership interest in the NOARK Pipeline System, Limited Partnership (NOARK) using the equity method of accounting. In accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," the Company recognizes profit on intercompany sales of gas delivered to storage by its utility subsidiary.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Minority Interest in Partnership

In 2001, SEPCO formed a limited partnership, Overton Partners, L.P., with an investor to drill and complete the first 14 development wells in SEPCO's Overton Field located in Smith County, Texas. Because SEPCO is the sole general partner and owns a majority interest in the partnership, the operating and financial results are consolidated with the Company's exploration and production results and the investor's share of the partnership activity is reported as a minority interest item in the financial statements. SEPCO contributed 50% of the capital required to drill the first 14 wells. Revenues and expenses are allocated 65% to SEPCO prior to payout of the investor's initial investment and 85% thereafter.

Unusual Items

In June 2000, the Company reported that the Arkansas Supreme Court ruled to affirm the 1998 decision of the Sebastian County Circuit Court awarding $109.3 million in a class action to royalty owners of SEECO, Inc. (Hales judgment). The Company fully satisfied the judgment and the Circuit Court in Sebastian County issued an order in complete satisfaction of the judgment effective July 18, 2000. Additionally, the Company incurred an unusual charge of $2.0 million during 2000 related to other litigation.

Property, Depreciation, Depletion and Amortization

Gas and Oil Properties. The Company follows the full cost method of accounting for the exploration, development, and acquisition of gas and oil reserves. Under this method, all such costs (productive and nonproductive) including salaries, benefits, and other internal costs directly attributable to these activities are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. The Company excludes all costs of unevaluated properties from immediate amortization. The Company's unamortized costs of oil and gas properties are limited to the sum of the future net revenues attributable to proved oil and gas reserves discounted at 10 percent plus the lower of cost or market value of any unproved properties. If the Company's unamortized costs in oil and gas properties exceed this ceiling amount, a provision for additional depreciation, depletion and amortization is required. At December 31, 2001, the Company's net book value of oil and gas properties did not exceed the ceiling amount. Decreases in market prices from December 31, 2001 levels, as well as changes in production rates, levels of reserves, and the evaluation of costs excluded from amortization, could result in future ceiling test impairments.

Gas Distribution Systems. Costs applicable to construction activities, including overhead items, are capitalized. Depreciation and amortization of the gas distribution system is provided using the straight-line method with average annual rates for plant functions ranging from 1.5% to 5.8%. Gas in underground storage is stated at average cost.

Other property, plant and equipment is depreciated using the straight-line method over estimated useful lives ranging from 5 to 40 years.

The Company charges to maintenance or operations the cost of labor, materials, and other expenses incurred in maintaining the operating efficiency of its properties. Betterments are added to property accounts at cost. Retirements are credited to property, plant and equipment at cost and charged to accumulated depreciation, depletion and amortization with no gain or loss recognized, except for abnormal retirements.

Capitalized Interest. Interest is capitalized on the cost of unevaluated gas and oil properties excluded from amortization. In accordance with established utility regulatory practice, an allowance for funds used during construction of major projects is capitalized and amortized over the estimated lives of the related facilities.

Gas Distribution Revenues and Receivables

Customer receivables arise from the sale or transportation of gas by the Company's gas distribution subsidiary. The Company's 136,000 gas distribution customers are located in northern Arkansas and represent a diversified base of residential, commercial, and industrial users. The Company records gas distribution revenues on an accrual basis, as gas volumes are used, to provide a proper matching of revenues with expenses.

The gas distribution subsidiary's rate schedules include purchased gas adjustment clauses whereby the actual cost of purchased gas above or below the level included in the base rates is permitted to be billed or is required to be credited to customers. Each month, the difference between actual costs of purchased gas and gas costs recovered from customers is deferred. The deferred differences are billed or credited, as appropriate, to customers in subsequent months. Rate schedules include a weather normalization clause to lessen the impact of revenue increases and decreases which might result from weather variations during the winter heating season. The pass-through of gas costs to customers is not affected by this normalization clause.

Gas Production Imbalances

The exploration and production subsidiaries record gas sales using the entitlement method. The entitlement method requires revenue recognition of the Company's revenue interest share of gas production from properties in which gas sales are disproportionately allocated to owners because of marketing or other contractual arrangements. The Company's net imbalance position at December 31, 2001 and 2000 was not significant.

Income Taxes

Deferred income taxes are provided to recognize the income tax effect of reporting certain transactions in different years for income tax and financial reporting purposes.

Risk Management

The Company uses derivative financial instruments to manage defined commodity price risks and interest rate risks and does not use them for trading purposes. The Company uses commodity swap agreements and options to hedge sales and purchases of natural gas and sales of crude oil. Gains and losses resulting from hedging activities have been recognized in the statements of operations when the related physical transactions of commodities were recognized. Gains or losses from commodity swap agreements and options that do not qualify for accounting treatment as hedges would be recognized currently as other income or expense. See Note 8 for a discussion of the Company's hedging activities and the effects of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities."

Earnings Per Share and Shareholders' Equity

Basic earnings per common share is computed by dividing net income by the weighted average number of common shares outstanding during each year. The diluted earnings per share calculation adds to the weighted average number of common shares outstanding the incremental shares that would have been outstanding assuming the exercise of dilutive stock options. The Company had options for 2,602,800 shares with an average exercise price of $9.79 outstanding at December 31, 2000 that, due to the Company's net loss for 2000, would have had an anti-dilutive effect and were, therefore, not considered. The Company had options for 1,006,234 shares of common stock with a weighted average exercise price of $13.83 per share at December 31, 2001, and options for 1,275,899 shares of common stock with a weighted average exercise price of $12.97 per share at December 31, 1999, that were not included in the calculation of diluted shares because they would have had an anti-dilutive effect. The remaining 1,665,952 options at December 31, 2001 with a weighted average exercise price of $7.43, and 785,300 options at December 31, 1999 with a weighted average exercise price of $6.46 were included in the calculation of diluted shares.

During 2001 and 2000, the Company issued 299,850 and 154,438 treasury shares, respectively, under a compensatory plan and for stock awards and returned to treasury 18,184 and 10,955 shares, respectively, canceled from earlier issues under the compensatory plan. The net effect of these transactions was a reduction in treasury stock of $3.3 million and $1.6 million in 2001 and 2000, respectively.

Dividend on Common Stock

As a result of the adverse Hales judgment in June 2000, the Company has indefinitely suspended payment of quarterly dividends on its common stock.

(2) DEBT

Debt balances as of December 31, 2001 and 2000 consisted of the following:

	2001	2000
	(in thousands)	
Senior notes		
6.70% Series due 2005	$ 125,000	$ 125,000
7.625% Series due 2027, putable at the holders' option in 2009	60,000	60,000
7.21% Series due 2017	40,000	40,000
	225,000	225,000
Other		
Variable rate (3.44% at December 31, 2001) unsecured revolving credit arrangements	125,000	–
Total long-term debt	$ 350,000	$ 225,000
Short-term debt		
Variable rate unsecured revolving credit arrangements	$ –	$ 171,000

In July 2001, the Company arranged a new unsecured revolving credit facility with a group of banks to replace its existing short-term credit facility that was put in place in July 2000. The new revolving credit facility has a current capacity of $155 million and a three-year term. The capacity of the revolving credit facility decreases to $140 million in June 2002 and to $125 million in June 2003. The interest rate on the new facility is 137.5 basis points over the current London Interbank

Offered Rate (LIBOR). The new credit facility contains covenants which impose certain restrictions on the Company. Under the credit agreement, the Company may not issue total debt in excess of 70% of its total capital, must maintain a certain level of shareholders' equity, and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of at least 3.75 or higher through December 31, 2002. These covenants change over the term of the credit facility and generally become more restrictive. The Company was in compliance with its debt agreements at December 31, 2001. The Company has entered into interest rate swaps for calendar year 2002 that allow the Company to pay an average fixed interest rate of 4.8% (based upon current rates under the revolving credit facility) on $100 million of its outstanding revolving debt.

There are no aggregate maturities of long-term debt for each of the years ending December 31, 2002, 2003 and 2006. For each of the years ended December 31, 2004 and 2005, the aggregate maturity is $125.0 million. Total interest payments were $24.4 million in 2001, $23.6 million in 2000, and $19.6 million in 1999.

(3) INCOME TAXES

The provision (benefit) for income taxes included the following components:

	2001	2000	1999
		(in thousands)	
Federal:			
Current	$ –	$ –	$ –
Deferred	19,461	(23,723)	5,236
State:			
Current	–	–	537
Deferred	2,575	(5,063)	795
Investment tax credit amortization	(119)	(119)	(119)
Provision (benefit) for income taxes	$ 21,917	$ (28,905)	$ 6,449

The provision (benefit) for income taxes was an effective rate of 38.3% in 2001, 38.7% in 2000, and 39.4% in 1999. The following reconciles the provision (benefit) for income taxes included in the consolidated statements of operations with the provision (benefit) which would result from application of the statutory federal tax rate to pretax financial income:

	2001	2000	1999
		(in thousands)	
Expected provision (benefit) at federal statutory rate of 35%	$ 20,034	$ (26,145)	$ 5,732
Increase (decrease) resulting from:			
State income taxes, net of federal income tax effect	1,674	(3,291)	866
Other	209	531	(149)
Provision (benefit) for income taxes	$ 21,917	$ (28,905)	$ 6,449

The components of the Company's net deferred tax liability as of December 31, 2001 and 2000 were as follows:

	2001	2000
	(in thousands)	
Deferred tax liabilities:		
Differences between book and tax basis of property	$ 148,330	$ 129,702
Stored gas	8,037	8,883
Deferred purchased gas costs	–	11,313
Prepaid pension costs	1,908	1,884
Book over tax basis in partnerships	11,148	11,755
Other	6,694	1,072
	176,117	164,609
Deferred tax assets:		
Accrued compensation	721	884
Alternative minimum tax credit carryforward	3,766	3,046
Net operating loss carryforward	48,595	63,449
Other	1,849	1,671
	54,931	69,050
Net deferred tax liability	$ 121,186	$ 95,559

There were no income tax payments in 2001. Total income tax payments of $.5 million and $.6 million were made in 2000 and 1999, respectively.

(4) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company applies SFAS No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits." Substantially all employees are covered by the Company's defined benefit pension and postretirement benefit plans. The following provides a reconciliation of the changes in the plans' benefit obligations, fair value of assets, and funded status as of December 31, 2001 and 2000:

	Pension Benefits		Other Postretirement Benefits	
	2001	2000	2001	2000
	(in thousands)			
Change in benefit obligations:				
Benefit obligation at January 1	$ 56,571	$ 61,515	$ 2,011	$ 3,759
Service cost	1,318	1,682	71	85
Interest cost	4,133	4,509	138	268
Actuarial loss (gain)	3,338	1,438	10	(226)
Benefits paid	(4,435)	(7,256)	(131)	(138)
Amount transferred	–	(5,317)	–	–
Effect of settlement	–	–	–	(1,737)
Benefit obligation at December 31	$ 60,925	$ 56,571	$ 2,099	$ 2,011
Change in plan assets:				
Fair value of plan assets at January 1	$ 66,283	$ 70,478	$ 573	$ 615
Actual return on plan assets	(2,478)	8,716	2	4
Employer contributions	18	13	228	308
Benefit payments	(4,435)	(7,256)	(131)	(138)
Amount transferred	(378)	(5,668)	–	–
Effect of settlement	–	–	–	(216)
Fair value of plan assets at December 31	$ 59,010	$ 66,283	$ 672	$ 573
Funded status:				
Funded status at December 31	$ (1,916)	$ 9,712	$ (1,427)	$ (1,438)
Unrecognized net actuarial (gain) loss	2,288	(9,832)	322	299
Unrecognized prior service cost	4,514	4,965	–	–
Unrecognized transition obligation	–	(37)	946	1,032
Prepaid (accrued) benefit cost	$ 4,886	$ 4,808	$ (159)	$ (107)

The Company's supplemental retirement plan has an accumulated benefit obligation in excess of plan assets. The plan's accumulated benefit obligation was $326,000 and $286,000 at December 31, 2001 and 2000, respectively. There are no plan assets in the supplemental retirement plan due to the nature of the plan.

Net periodic pension and other postretirement benefit costs include the following components for 2001, 2000 and 1999:

	Pension Benefits			Other Postretirement Benefits		
	2001	2000	1999	2001	2000	1999
	(in thousands)					
Service cost	$ 1,318	$ 1,682	$ 1,881	$ 71	$ 85	$ 99
Interest cost	4,133	4,509	4,130	138	268	261
Expected return on plan assets	(5,829)	(6,190)	(6,259)	(34)	(39)	(28)
Amortization of transition obligation	(36)	(183)	(183)	86	103	103
Recognized net actuarial (gain) loss	(97)	(142)	(142)	19	63	111
Amortization of prior service cost	451	451	451	–	–	–
	$ (60)	$ 127	$ (122)	$ 280	$ 480	$ 546

The Company's pension plans provide for benefits on a "cash balance" basis. A cash balance plan provides benefits based upon a fixed percentage of an employee's annual compensation. The Company's funding policy is to contribute amounts which are actuarially determined to provide the plans with sufficient assets to meet future benefit payment requirements and which are tax deductible.

The postretirement benefit plans provide contributory health care and life insurance benefits. Employees become eligible for these benefits if they meet age and service requirements. Generally, the benefits paid are a stated percentage of medical expenses reduced by deductibles and other coverages. The Company has established trusts to partially fund its postretirement benefit obligations.

The weighted average assumptions used in the measurement of the Company's benefit obligations for 2001 and 2000 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2001	2000	2001	2000
Discount rate	7.00 %	7.25 %	7.00 %	7.25 %
Expected return on plan assets	9.00 %	9.00 %	5.00 %	5.00 %
Rate of compensation increase	4.50 %	4.50 %	n/a	n/a

For measurement purposes an 8% annual rate of increase in the per capita cost of covered medical benefits and a 7.5% annual rate of increase in the per capita cost of dental benefits was assumed for 2002. These rates were assumed to gradually decrease to 6% for medical benefits and 5% for dental benefits for 2011 and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in thousands)	
Effect on the total service and interest cost components	$ 29	$ (25)
Effect on postretirement benefit obligation	$ 265	$ (230)

(5) NATURAL GAS AND OIL PRODUCING ACTIVITIES

All of the Company's gas and oil properties are located in the United States. The table below sets forth the results of operations from gas and oil producing activities:

	2001	2000	1999
		(in thousands)	
Sales	$ 153,937	$ 110,920	$ 75,039
Production (lifting) costs	(23,604)	(19,804)	(14,039)
Depreciation, depletion and amortization	(46,530)	(39,048)	(34,230)
	83,803	52,068	26,770
Income tax expense	(31,819)	(20,023)	(10,528)
Results of operations	$ 51,984	$ 32,045	$ 16,242

The results of operations shown above exclude unusual items in 2000 and overhead and interest costs in all years. Income tax expense is calculated by applying the statutory tax rates to the revenues less costs, including depreciation, depletion and amortization, and after giving effect to permanent differences and tax credits.

The table below sets forth capitalized costs incurred in gas and oil property acquisition, exploration and development activities during 2001, 2000 and 1999:

	2001	2000	1999
		(in thousands)	
Proved property acquisition costs	$ 7,323	$ 7,428	$ 10,456
Unproved property acquisition costs	4,482	5,941	9,389
Exploration costs	23,490	27,853	19,519
Development costs	63,103	27,519	19,059
Capitalized costs incurred	$ 98,398	$ 68,741	$ 58,423
Amortization per Mcf equivalent	$1.14	$1.06	$1.00

Capitalized interest is included as part of the cost of oil and gas properties. The Company capitalized $1.6 million, $2.4 million and $3.3 million during 2001, 2000 and 1999, respectively, based on the Company's weighted average cost of borrowings used to finance the expenditures.

In addition to capitalized interest, the Company also capitalized internal costs of $8.3 million, $7.3 million and $7.4 million during 2001, 2000 and 1999, respectively. These internal costs were directly related to acquisition, exploration and development activities and are included as part of the cost of oil and gas properties.

The following table shows the capitalized costs of gas and oil properties and the related accumulated depreciation, depletion and amortization at December 31, 2001 and 2000:

	2001	2000
	(in thousands)	
Proved properties	$ 944,502	$ 841,875
Unproved properties	26,178	30,148
Total capitalized costs	970,680	872,023
Less: Accumulated depreciation, depletion and amortization	502,882	457,551
Net capitalized costs	$ 467,798	$ 414,472

The table below sets forth the composition of net unevaluated costs excluded from amortization as of December 31, 2001. Of the total, approximately $11.5 million is invested in Louisiana. The majority of Louisiana costs are related to seismic projects that will be evaluated over several years as the seismic data is interpreted and the acreage is explored. The remaining costs excluded from amortization are related to properties which are not individually significant and on which the evaluation process has not been completed. The Company is, therefore, unable to estimate when these costs will be *included in the amortization computation.*

	2001	2000	1999	Prior	Total
			(in thousands)		
Property acquisition costs	$ 4,385	$ 1,880	$ 913	$ 2,432	$ 9,610
Exploration costs	725	1,891	3,434	2,155	8,205
Capitalized interest	225	566	782	1,714	3,287
	$ 5,335	$ 4,337	$ 5,129	$ 6,301	$ 21,102

(6) NATURAL GAS AND OIL RESERVES (UNAUDITED)

The following table summarizes the changes in the Company's proved natural gas and oil reserves for 2001, 2000 and 1999:

	2001		2000		1999	
	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)
Proved reserves, beginning of year	331,754	8,130	307,523	7,859	303,667	6,850
Revisions of previous estimates	(21,598)	(979)	5,357	(22)	(7,464)	1,155
Extensions, discoveries, and other additions	77,187	1,272	53,389	1,347	34,730	225
Production	(35,477)	(719)	(31,602)	(676)	(29,444)	(578)
Acquisition of reserves in place	4,325	21	8,100	82	9,762	576
Disposition of reserves in place	(378)	(21)	(11,013)	(460)	(3,728)	(369)
Proved reserves, end of year	355,813	7,704	331,754	8,130	307,523	7,859
Proved, developed reserves:						
Beginning of year	270,830	7,100	250,290	7,154	258,092	6,370
End of year	281,461	6,429	270,830	7,100	250,290	7,154

The "Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves" (standardized measure) is a disclosure required by SFAS No. 69, "Disclosures About Oil and Gas Producing Activities." The standardized measure does not purport to present the fair market value of a company's proved gas and oil reserves. In addition, there are uncertainties inherent in estimating quantities of proved reserves. Substantially all quantities of gas and oil reserves owned by the Company were estimated or audited by the independent petroleum engineering firm of K & A Energy Consultants, Inc.

Following is the standardized measure relating to proved gas and oil reserves at December 31, 2001, 2000 and 1999:

	2001	2000	1999
		(in thousands)	
Future cash inflows	$ 1,095,843	$ 3,366,304	$ 989,997
Future production costs	(313,357)	(461,808)	(195,131)
Future development costs	(57,136)	(44,609)	(32,230)
Future income tax expense	(182,103)	(974,273)	(247,408)
Future net cash flows	543,247	1,885,614	515,228
10% annual discount for estimated timing of cash flows	(235,087)	(990,472)	(253,153)
Standardized measure of discounted future net cash flows	$ 308,160	$ 895,142	$ 262,075

Under the standardized measure, future cash inflows were estimated by applying year-end prices, adjusted for known contractual changes, to the estimated future production of year-end proved reserves. Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pretax cash inflows. Future income taxes were computed by applying the year-end statutory rate, after consideration of permanent differences, to the excess of pretax cash inflows over the Company's tax basis in the associated proved gas and oil properties. Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the standardized measure.

Following is an analysis of changes in the standardized measure during 2001, 2000 and 1999:

	2001	2000	1999
		(in thousands)	
Standardized measure, beginning of year	$ 895,142	$ 262,075	$ 222,793
Sales and transfers of gas and oil produced, net of production costs	(130,333)	(91,116)	(61,000)
Net changes in prices and production costs	(979,522)	837,691	48,506
Extensions, discoveries, and other additions, net of future production and development costs	102,832	259,212	48,279
Acquisition of reserves in place	5,406	33,032	14,765
Revisions of previous quantity estimates	(24,966)	20,178	(612)
Accretion of discount	133,136	38,076	32,447
Net change in income taxes	349,862	(317,527)	(17,015)
Changes in production rates (timing) and other	(43,397)	(146,479)	(26,088)
Standardized measure, end of year	$ 308,160	$ 895,142	$ 262,075

(7) INVESTMENT IN UNCONSOLIDATED PARTNERSHIP

The Company holds a 25% general partnership interest in NOARK. NOARK Pipeline was formerly a 258-mile intrastate gas transmission system which extended across northern Arkansas. In January 1998, the Company entered into an agreement with Enogex Inc. (Enogex) that resulted in the expansion of the NOARK Pipeline and provided the pipeline with access to Oklahoma gas supplies through an integration of NOARK with the Ozark Gas Transmission System (Ozark). Enogex is a subsidiary of OGE Energy Corp. Ozark was a 437-mile interstate pipeline system which began in eastern Oklahoma and terminated in eastern Arkansas. Enogex acquired the Ozark system and contributed it to NOARK. Enogex also acquired the NOARK partnership interests not owned by Southwestern. The acquisition of Ozark and its integration with NOARK Pipeline was approved by the Federal Energy Regulatory Commission in late 1998 at which time NOARK Pipeline was converted to an interstate pipeline and operated in combination with Ozark. Enogex funded the acquisition of Ozark and the expansion and integration with NOARK Pipeline which resulted in the Company's ownership interest in the partnership decreasing to 25% from 48%.

The Company's investment in NOARK totaled $15.5 million at December 31, 2001 and 2000, including advances of $1.4 million made during 2001, $3.3 million made during 2000 and $2.3 million made during 1999. Advances are made primarily to service NOARK's long-term debt. See Note 11 for further discussion of NOARK's funding requirements and the Company's investment in NOARK.

NOARK's financial position at December 31, 2001 and 2000 is summarized below:

	2001	2000
	(in thousands)	
Current assets	$ 8,363	$ 9,532
Noncurrent assets	175,299	179,136
	$ 183,662	$ 188,668
Current liabilities	$ 7,403	$ 11,803
Long-term debt	71,000	73,000
Partners' capital	105,259	103,865
	$ 183,662	$ 188,668

The Company's share of NOARK's pretax loss was $1.5 million, $1.8 million and $2.0 million for 2001, 2000 and 1999, respectively. The Company records its share of NOARK's pretax loss in other income (expense) on the statements of operations.

NOARK's results of operations for 2001, 2000 and 1999 are summarized below:

	2001	2000	1999
		(in thousands)	
Operating revenues	$ 81,662	$ 73,633	$ 40,358
Pretax net loss	$ (1,047)	$ (1,391)	$ (3,564)

(8) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate the value:

Cash, Customer Deposits, and Short-Term Debt: The carrying amount is a reasonable estimate of fair value.

Long-Term Debt: The fair value of the Company's long-term debt is estimated based on the expected current rates which would be offered to the Company for debt of the same maturities.

Commodity and Interest Hedges: The fair value of all hedging financial instruments is the amount at which they could be settled, based on quoted market prices or estimates obtained from dealers. The carrying amounts and estimated fair values of the Company's financial instruments as of December 31, 2001 and 2000 were as follows:

	2001		2000	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(in thousands)		
Cash	$ 3,641	$ 3,641	$ 2,386	$ 2,386
Customer deposits	$ 4,845	$ 4,845	$ 4,799	$ 4,799
Short-term debt	–	–	$ 171,000	$ 171,000
Long-term debt	$ 350,000	$ 356,179	$ 225,000	$ 226,309
Commodity and interest hedges	$ 3,246	$ 3,246	$ (160)	$ (60,596)

Derivatives and Risk Management

SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 137 and SFAS No. 138, was adopted by the Company on January 1, 2001. SFAS No. 133 requires that all derivatives be recognized in the balance sheet as either an asset or liability measured at its fair value. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement.

Upon adoption of SFAS No. 133 on January 1, 2001, the Company recorded a transition obligation of $60.6 million related to cash flow hedges in place that are intended to reduce the volatility in commodity prices for the Company's forecasted oil and gas production. At December 31, 2001, the Company recorded hedging assets of $10.3 million, hedging liabilities of $7.1 million, a regulatory asset of $5.8 million related to its utility gas purchase hedges, and a net of tax gain to other comprehensive income (equity section of the balance sheet) of $5.8 million. The amount recorded in other comprehensive income will be relieved over time and taken to the income statement as the physical transactions being hedged occur. There was no significant ineffectiveness during 2001 related to the Company's cash flow hedges and there were no discontinued hedges. Additional volatility in earnings and other comprehensive income may occur in the future as a result of the adoption of SFAS No. 133.

The Company uses natural gas and crude oil swap agreements and options and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil and in interest rates. The Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price and interest rate risks. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

The Company uses over-the-counter natural gas and crude oil swap agreements and options to hedge sales of Company production, to hedge activity in its marketing segment, and to hedge the purchase of gas in its utility segment against the inherent price risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX (New York Mercantile Exchange) futures market. These swaps and options include (1) transactions in which one party will pay a fixed price (or variable price) for a notional quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps), (2) transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps), and (3) the purchase and sale of index-related puts and calls (collars) that provide a "floor" price below which the counterparty pays (production hedge) or receives (gas purchase hedge) funds equal to the amount by which the price of the commodity is below the contracted floor, and a "ceiling" price above which the Company pays to (production hedge) or receives from (gas purchase hedge) the counterparty the amount by which the price of the commodity is above the contracted ceiling.

At December 31, 2001, the Company had outstanding natural gas price swaps on total notional volumes of 13.4 Bcf in 2002 and 9.2 Bcf in 2003 for which the Company will receive fixed prices ranging from $2.57 to $3.20 per MMBtu. Under contracts on .3 Bcf in 2002, the Company will make average fixed price payments of $2.96 per MMBtu and receive variable prices based on the NYMEX futures market. At December 31, 2001, the Company also had outstanding natural gas price swaps on total notional gas purchase volumes of 3.3 Bcf in 2002 for which the Company will pay an average fixed price of $4.20 per Mcf.

At December 31, 2001, the Company had collars in place on 6.0 Bcf in 2002 and 4.1 Bcf in 2003 of future gas production. The 6.0 Bcf in 2002 had a floor and ceiling of $4.00 and $4.72, respectively. The 4.1 Bcf in 2003 had a floor and ceiling of $3.00 and $4.65, respectively. The Company's price risk management activities reduced revenues $10.3 million in 2001, $39.3 million in 2000, and $1.1 million in 1999.

The Company has outstanding interest rate swaps on a notional amount of $100 million. Under these contracts the Company will make average fixed interest payments at 3.4% and receive variable prices based on the one-month LIBOR rate. The Company currently pays an additional 1.4% above LIBOR on its revolving credit facility.

The primary market risks related to the Company's derivative contracts are the volatility in commodity prices, basis differentials and interest rates. However these market risks are offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of oil that is hedged, and payment of variable rate interest. Credit risk relates to the risk of loss as a result of non-performance by the Company's counterparties. The counterparties are primarily major investment and commercial banks which management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure the Company has to each counterparty are periodically reviewed to ensure limited credit risk exposure.

(9) STOCK OPTIONS

The Southwestern Energy Company 2000 Stock Incentive Plan (2000 Plan) was adopted in February 2000 and provides for the compensation of officers, key employees and eligible non-employee directors of the Company and its subsidiaries. The 2000 Plan replaces the Southwestern Energy Company 1993 Stock Incentive Plan (1993 Plan) and the Southwestern Energy Company 1993 Stock Incentive Plan for Outside Directors (1993 Director Plan). The 2000 Plan provides for grants of options, stock appreciation rights, shares of phantom stock, and shares of restricted stock that in the aggregate do not exceed 1,250,000 shares. The types of incentives which may be awarded are comprehensive and are intended to enable the Board of Directors to structure the most appropriate incentives and to address changes in income tax laws which may be enacted over the term of the 2000 Plan.

The 1993 Plan provided for the compensation of officers and key employees of the Company and its subsidiaries through grants of options, shares of restricted stock, and stock bonuses that in the aggregate did not exceed 1,700,000 shares, the grant of stand-alone stock appreciation rights (SARs), shares of phantom stock and cash awards, the shares related to which in the aggregate did not exceed 1,700,000 shares, and the grant of limited and tandem SARs (all terms as defined in the 1993 Plan). The Company has also awarded stock option grants outside the 2000 Plan and the 1993 Plan to certain non-officer employees and to certain officers at the time of their hire.

The 2000 Plan awards each non-employee director who is eligible to participate in the plan an annual Director's Option with respect to 8,000 shares of common stock. Previously, the 1993 Director Plan provided for annual stock option grants of 12,000 shares (with 12,000 limited SARs) to each non-employee director. Options under the 1993 Director Plan were limited to no more than 240,000 shares.

The Company's 1985 Nonqualified Stock Option Plan expired in 1992, except with respect to awards then outstanding. The following tables summarize stock option activity for the years 2001, 2000 and 1999 and provide information for options outstanding at December 31, 2001:

	2001		2000		1999	
	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
Options outstanding at January 1	2,602,800	$ 9.79	2,061,199	$ 10.49	1,634,901	$ 12.15
Granted	170,200	$ 10.13	666,100	$ 7.58	562,250	$ 6.18
Exercised	11,252	$ 7.00	–	–	1,333	$ 7.31
Canceled	89,562	$ 9.22	124,499	$ 9.55	134,619	$ 12.68
Options outstanding at December 31	2,672,186	$ 9.84	2,602,800	$ 9.79	2,061,199	$ 10.49

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Options Outstanding at Year End	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Options Exercisable at Year End	Weighted Average Exercise Price
$ 6.00 - $ 7.00	558,018	$ 6.15	7.8	368,226	$ 6.15
$ 7.06 - $ 8.75	834,934	$ 7.41	8.2	441,229	$ 7.39
$ 9.06 - $ 13.38	740,300	$ 11.65	6.4	536,267	$ 12.26
$ 14.00 - $ 17.50	538,934	$ 14.95	3.3	480,372	$ 14.99
	2,672,186	$ 9.84		1,826,094	$ 10.57

All options are issued at fair market value at the date of grant and expire ten years from the date of grant. Options generally vest to employees and directors over a three to four year period from the date of grant. Of the total options outstanding, 325,000 performance accelerated options were granted in 1994 at an option price of $14.63. These options vest over a four-year period beginning in 2000.

The Company applies the disclosure-only provisions of SFAS No. 123, "Accounting for Stock-Based Compensation." Accordingly, no compensation cost has been recognized for the stock option plans. Had compensation cost for the Company's stock option plans been determined consistent with the provisions of SFAS No. 123, the Company's net income (loss) and earnings (loss) per share would have been reduced to the pro forma amounts indicated below:

	2001	2000	1999
Net income (loss), in thousands			
As reported	$ 35,324	$ (46,687)	$ 9,927
Pro forma	$ 34,373	$ (47,444)	$ 9,241
Basic earnings (loss) per share			
As reported	$ 1.40	$ (1.86)	$ .40
Pro forma	$ 1.36	$ (1.90)	$ .37
Diluted earnings (loss) per share			
As reported	$ 1.38	$ (1.86)	$ .40
Pro forma	$ 1.34	$ (1.90)	$ .37

Because the SFAS No. 123 method of accounting has not been applied to options granted prior to January 1, 1995, the resulting pro forma compensation cost may not be representative of that to be expected in future years. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions: no dividend yield; expected volatility of 46.4%; risk-free interest rate of 4.8%; and expected lives of 6 years.

The Company has granted 752,995 shares of restricted stock to employees through 2001. Of this total, 421,895 shares vest over a three-year period, 288,550 shares vest over a four-year period, and the remaining shares vest over a five-year period. The related compensation expense is being amortized over the vesting periods. As of December 31, 2001, 295,146 shares have vested to employees and 41,480 shares have been canceled and returned to treasury shares.

(10) COMMON STOCK PURCHASE RIGHTS

In 1999, the Company's Common Share Purchase Rights Plan was amended and extended for an additional ten years. Per the terms of the amended plan, one common share purchase right is attached to each outstanding share of the Company's common stock. Each right entitles the holder to purchase one share of common stock at an exercise price of $40.00, subject to adjustment. These rights will become exercisable in the event that a person or group acquires or commences a tender or exchange offer for 15% or more of the Company's outstanding shares or the Board determines that a holder of 10% or more of the Company's outstanding shares presents a threat to the best interests of the Company. At no time will these rights have any voting power.

If any person or entity actually acquires 15% of the common stock (10% or more if the Board determines such acquiror is adverse), rightholders (other than the 15% or 10% stockholder) will be entitled to buy, at the right's then current exercise price, the Company's common stock with a market value of twice the exercise price. Similarly, if the Company is acquired in a merger or other business combination, each right will entitle its holder to purchase, at the right's then current exercise price, a number of the surviving company's common shares having a market value at that time of twice the right's exercise price.

The rights may be redeemed by the Board for $.01 per right or exchanged for common shares on a one-for-one basis prior to the time that they become exercisable. In the event, however, that redemption of the rights is considered in connection with a proposed acquisition of the Company, the Board may redeem the rights only on the recommendation of its independent directors (nonmanagement directors who are not affiliated with the proposed acquiror). These rights expire in 2009.

(11) CONTINGENCIES AND COMMITMENTS

The Company and the other general partner of NOARK have severally guaranteed the principal and interest payments on NOARK's 7.15% Notes due 2018. The Company's share of the several guarantee is 60%. At December 31, 2001 and 2000, the principal outstanding for these Notes was $73.0 million and $75.0 million, respectively. The Notes were issued in June 1998 and require semi-annual principal payments of $1.0 million. Under the several guarantee, the Company is required to fund its share of NOARK's debt service which is not funded by operations of the pipeline. As a result of the integration of NOARK Pipeline with the Ozark Gas Transmission System, as discussed further in Note 7, management of the Company believes that it will realize its investment in NOARK over the life of the system. Therefore, no provision for any loss has been made in the accompanying financial statements. Additionally, the Company's gas distribution subsidiary has transportation contracts for firm capacity of 66.9 MMcfd on NOARK's integrated pipeline system. These contracts expire in 2002 and 2003, and are renewable year-to-year thereafter until terminated by 180 days' notice.

The Company recently settled litigation, subject to court approval, in a case filed against the Company and two of its subsidiaries in a state court in Sebastian County, Arkansas related to the Company's Stockton Gas Storage Facility in Franklin County, Arkansas (the "Stockton Storage Facility"). As previously disclosed, this class action suit was filed on August 25, 2000 on behalf of a class of plaintiffs comprised of all surface owners, mineral owners, royalty owners and overriding royalty owners in the Stockton Storage Facility. Plaintiffs alleged various wrongful, intentional and fraudulent acts relating to the operation of the storage pool beginning in 1968 and continuing to the present, and claimed ownership rights in the gas that the Company has stored in the storage pool in an amount in excess of $5 million in actual damages, interest, attorney's fees and punitive damages. Under the terms of the settlement, the Company has agreed to pay the plaintiffs a cash settlement amount and enter into new gas storage agreements at rental rates commensurate with current market prices. The settlement of this litigation did not have a material impact on the Company's result of operations for 2001.

The Company is subject to laws and regulations relating to the protection of the environment. The Company's policy is to accrue environmental and cleanup related costs of a non-capital nature when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on the financial position or reported results of operations of the Company.

The Company is subject to other litigation and claims that have arisen in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such litigation and claims will not have a material effect on the results of operations or the financial position of the Company.

(12) SEGMENT INFORMATION

The Company applies SFAS No. 131, "Disclosures About Segments of an Enterprise and Related Information." The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the exploration and production segment are derived from the production and sale of natural gas and crude oil. Revenues for the gas distribution segment arise from the transportation and sale of natural gas at retail. The marketing segment generates revenue through the marketing of both Company and third party produced gas volumes.

Summarized financial information for the Company's reportable segments is shown in the following table. The "Other" column includes items related to non-reportable segments (real estate and pipeline operations) and corporate items.

	Exploration and Production	Gas Distribution	Marketing	Other	Total
2001			(in thousands)		
Revenues from external customers	$ 126,006	$ 147,082	$ 71,839	$ –	$ 344,927
Intersegment revenues	27,931	200	118,486	448	147,065
Operating income	69,340	10,346	2,703	280	82,669
Depreciation, depletion and amortization expense	46,530	6,163	111	95	52,899
Interest expense (1)	18,238	4,413	34	1,014	23,699
Provision (benefit) for income taxes (1)	19,164	2,505	996	(748)	21,917
Assets	526,346	169,931	8,026	38,820 (2)	743,123
Capital expenditures	98,964 (3)	5,347	–	1,749	106,060
2000					
Revenues from external customers	$ 75,597	$ 151,052	$ 137,234	$ –	$ 363,883
Intersegment revenues	35,323	182	70,514	448	106,467
Unusual items (4)	111,288	–	–	–	111,288
Operating income (loss)	(70,584)	14,655	2,460	–	(53,469)
Depreciation, depletion and amortization expense	39,048	6,625	109	87	45,869
Interest expense (1)	17,472	4,608	16	1,134	23,230
Provision (benefit) for income taxes (1)	(34,153)	4,869	912	(533)	(28,905)
Assets	460,296	188,811	20,929	35,342 (2)	705,378
Capital expenditures	69,211	5,994	24	488	75,717
1999					
Revenues from external customers	$ 51,533	$ 132,293	$ 96,570	$ –	$ 280,396
Intersegment revenues	23,506	127	40,956	416	65,005
Operating income	16,451	17,187	2,142	278	36,058
Depreciation, depletion and amortization expense	34,230	7,186	92	95	41,603
Interest expense (1)	11,345	5,027	–	979	17,351
Provision (benefit) for income taxes (1)	1,806	4,569	859	(785)	6,449
Assets	435,022	190,731	11,212	34,481 (2)	671,446
Capital expenditures	59,004	7,124	9	830	66,967

(1) Interest expense and the provision (benefit) for income taxes by segment are an allocation of corporate amounts as debt and income tax expense (benefit) are incurred at the corporate level.

(2) Other assets include the Company's equity investment in the operations of NOARK (see Note 7), corporate assets not allocated to segments, and assets for non-reportable segments.

(3) Includes $13.5 million funded by the owner of the minority interest in Overton partnership.

(4) Includes $109.3 million for the Hales judgment and $2.0 million for other litigation.

Intersegment sales by the exploration and production segment and marketing segment to the gas distribution segment are priced in accordance with terms of existing contracts and current market conditions. Parent company assets include furniture and fixtures, prepaid debt costs, and prepaid pension costs. Parent company general and administrative costs, depreciation expense and taxes other than income are allocated to segments. All of the Company's operations are located within the United States.

(13) QUARTERLY RESULTS (UNAUDITED)

The following is a summary of the quarterly results of operations for the years ended December 31, 2001 and 2000:

	Quarter ended			
	March 31	June 30	September 30	December 31
	(in thousands, except per share amounts)			
	2001			
Operating revenues	$ 137,129	$ 76,023	$ 59,396	$ 72,379
Operating income	$ 32,599	$ 18,015	$ 14,263	$ 17,792
Net income	$ 16,013	$ 6,869	$ 5,018	$ 7,424
Basic earnings per share	$ .64	$ .27	$ .20	$ .29
Diluted earnings per share	$ .63	$ .27	$ .20	$ .29
	2000			
Operating revenues	$ 96,913	$ 78,483	$ 75,342	$ 113,145
Operating income (loss)	$ 21,056	$ (101,849)	$ 5,884	$ 21,440
Net income (loss)	$ 9,186	$ (64,199)	$ (754)	$ 9,080
Basic and diluted earnings (loss) per share	$ .37	$ (2.57)	$ (.03)	$ .36

(14) NEW ACCOUNTING STANDARDS

In July 2001, the FASB issued Statement of Financial Accounting Standards No. 141, "Business Combinations" (SFAS No. 141), Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), and Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). In October, 2001, the FASB issued Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144).

SFAS No. 141 requires that the purchase method of accounting be used for all business combinations initiated after June 30, 2001. SFAS No. 142 requires that goodwill and intangible assets with indefinite useful lives no longer be amortized, but instead be tested for impairment at least annually in accordance with the provisions of SFAS No. 142. The Company was required to adopt the provisions of SFAS No. 141 immediately, and SFAS No. 142 effective January 1, 2002. Adoption of SFAS No. 141 and SFAS No. 142 had no impact on the Company's results of operations or financial condition.

SFAS No. 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs and amends FASB Statement No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the associated asset retirement costs be capitalized as part of the carrying amount of the long-lived asset. SFAS No. 143 is effective for financial statements issued for fiscal years beginning after June 15, 2002. The effect of this standard on the Company's results of operations and financial condition is being evaluated.

SFAS No. 144 supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of" and amends Accounting Principles Board Opinion No. 30, "Reporting the Results of Operations – Reporting the Effects of Disposal of a Segment of a Business and Extraordinary, Unusual and Infrequently Occurring Events and Transactions." SFAS No. 144 retains the basic framework of SFAS No. 121, resolves certain implementation issues of SFAS No. 121, extends applicability to discontinued operations, and broadens the presentation of discontinued operations to include a component of an entity. SFAS No. 144 is effective for financial statements issued for fiscal years beginning after December 15, 2001. Adoption of SFAS No. 144 had no impact on the Company's results of operations or financial position.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

There have been no changes in or disagreements with the Company's independent public accountants on accounting and financial disclosure.

Part III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The definitive Proxy Statement to holders of the Company's Common Stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Shareholders on May 15, 2002 (the 2002 Proxy Statement), is hereby incorporated by reference for the purpose of providing information about the identification of directors. Refer to the sections "Election of Directors" and "Share Ownership of Management and Directors" for information concerning the directors.

Information concerning executive officers is presented in Part I, Item 4 of this Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

The 2002 Proxy Statement is hereby incorporated by reference for the purpose of providing information about executive compensation. Refer to the section "Executive Compensation."

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The 2002 Proxy Statement is hereby incorporated by reference for the purpose of providing information about security ownership of certain beneficial owners and management. Refer to the sections "Security Ownership of Certain Beneficial Owners" and "Share Ownership of Management and Directors" for information about security ownership of certain beneficial owners and management.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The 2002 Proxy Statement is hereby incorporated by reference for the purpose of providing information about related transactions. Refer to the section "Share Ownership of Management and Directors" for information about transactions with members of the Company's Board of Directors.

Part IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) (1) The consolidated financial statements of the Company and its subsidiaries and the report of independent public accountants are included in Item 8 of this Report.

(2) The consolidated financial statement schedules have been omitted because they are not required under the related instructions, or are not applicable.

(3) The exhibits listed on the accompanying Exhibit Index (pages 67 and 68) are filed as part of, or incorporated by reference into, this Report.

(b) Reports on Form 8-K:

A Current Report on Form 8-K was filed on October 18, 2001, referencing a conference call conducted on October 17, 2001, announcing the results of the Company's third quarter 2001 activity.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused the report to be signed on its behalf by the undersigned, thereunto duly authorized.

SOUTHWESTERN ENERGY COMPANY
(Registrant)

Dated: March 29, 2002

BY: /s/ GREG D. KERLEY
Greg D. Kerley
Executive Vice President
and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on March 29, 2002.

/s/ HAROLD M. KORELL Harold M. Korell	President and Chief Executive Officer and Director
/s/ GREG D. KERLEY Greg D. Kerley	Executive Vice President and Chief Financial Officer
/s/ STANLEY T. WILSON Stanley T. Wilson	Controller and Chief Accounting Officer
/s/ CHARLES E. SCHARLAU Charles E. Scharlau	Director and Chairman
/s/ LEWIS E. EPLEY, JR. Lewis E. Epley, Jr.	Director
/s/ JOHN PAUL HAMMERSCHMIDT John Paul Hammerschmidt	Director
/s/ ROBERT L. HOWARD Robert L. Howard	Director
/s/ KENNETH R. MOURTON Kenneth R. Mourton	Director

Supplemental Information to be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant of Section 12 of the Act.

Not Applicable

EXHIBIT INDEX

Exhibit No.	Description
3.	Articles of Incorporation and Bylaws of the Company (amended and restated Articles of Incorporation incorporated by reference to Exhibit 3 to Annual Report on Form 10-K for the year ended December 31, 1993); Bylaws of the Company (amended Bylaws of the Company incorporated by reference to Exhibit 3 to Annual Report on Form 10-K for the year ended December 31, 1994).
4.1	Amended and Restated Rights Agreement dated April 12, 1999 (incorporated by reference to Exhibit 4.1 to Annual Report on Form 10-K for the year ended December 31, 1999), as amended by Amendment No. 1 to the Amended and Restated Rights Agreement dated March 15, 2002 (filed herewith).
4.2	Prospectus, Registration Statement, and Indenture on 6.70% Senior Notes due December 1, 2005 and issued December 5, 1995 (incorporated by reference to the Company's Forms S-3 and S-3/A filed on November 1, 1995, and November 17, 1995, respectively, and also to the Company's filings of a Prospectus and Prospectus Supplement on November 22, 1995, and December 4, 1995, respectively).
4.3	Prospectus Supplement and Form of Distribution Agreement on $125,000,000 of Medium-Term Notes dated February 21, 1997 (Prospectus Supplement incorporated by reference to the Company's filing of a Prospectus Supplement on February 21, 1997, Form of Distribution Agreement incorporated by reference to Exhibit 10 filed with the Company's Form 8-K dated February 21, 1997).
4.4	Short-Term Credit Agreement dated July 17, 2000 between Southwestern Energy Company and Bank One, N.A., as administrative agent, and Bank of America, N.A., as syndication agent (incorporated by reference to Exhibit 4.4 to Annual Report on Form 10-K for the year ended December 31, 2000).
4.5	Credit Agreement dated July 12, 2001 between Southwestern Energy Company and The Lenders; Bank One, N.A., as administrative agent, and Royal Bank of Canada, as syndication agent (filed herewith).
10.1	Compensation Plans:

(a) Southwestern Energy Company Incentive Compensation Plan, effective January 1, 1993, and Amended and Restated as of January 1, 1999 (incorporated by reference to Exhibit 10.2(b) to Annual Report on Form 10-K for the year ended December 31, 1998).

(b) Nonqualified Stock Option Plan, effective February 22, 1985, as amended July 10, 1989 (replaced by Southwestern Energy Company 1993 Stock Incentive Plan, dated April 7, 1993, which was replaced by the Southwestern Energy Company 2000 Stock Incentive Plan dated February 18, 2000) (original plan incorporated by reference to Exhibit 10 to Annual Report on Form 10-K for the year ended December 31, 1985; amended plan incorporated by reference to Exhibit 10 to Annual Report on Form 10-K for the year ended December 31, 1989).

(c) Southwestern Energy Company 1993 Stock Incentive Plan, dated April 7, 1993 and Amended and Restated as of February 18, 1998 (replaced by the Southwestern Energy Company 2000 Stock Incentive Plan dated February 18, 2000) (incorporated by reference to Exhibit 10.2(d) to Annual Report on Form 10-K for the year ended December 31, 1998).

(d) Southwestern Energy Company 1993 Stock Incentive Plan for Outside Directors, dated April 7, 1993 (replaced by the Southwestern Energy Company 2000 Stock Incentive Plan dated February 18, 2000) (incorporated by reference to the appendix filed with the Company's definitive Proxy Statement to holders of the Registrant's Common Stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Shareholders on May 26, 1993).

(e) Southwestern Energy Company 2000 Stock Incentive Plan dated February 18, 2000 (incorporated by reference to the appendix filed with the Company's definitive Proxy Statement to holders of the Registrant's Common Stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Shareholders on May 24, 2000).

Exhibit No.	Description
10.2	Southwestern Energy Company Supplemental Retirement Plan, adopted May 31, 1989, and Amended and Restated as of December 15, 1993, and as further amended February 1, 1996 (amended and restated plan incorporated by reference to Exhibit 10.5 to Annual Report on Form 10-K for the year ended December 31, 1993; amendment dated February 1, 1996, incorporated by reference to Exhibit 10.5 to Annual Report on Form 10-K for the year ended December 31, 1995).
10.3	Southwestern Energy Company Supplemental Retirement Plan Trust, dated December 30, 1993 (incorporated by reference to Exhibit 10.6 to Annual Report on Form 10-K for the year ended December 31, 1993).
10.4	Southwestern Energy Company Nonqualified Retirement Plan, effective October 4, 1995 (incorporated by reference to Exhibit 10.7 to Annual Report on Form 10-K for the year ended December 31, 1995).
10.5	Employment and Consulting Agreement for Charles E. Scharlau, dated May 21, 1998 (incorporated by reference to Exhibit 10.9 to Annual Report on Form 10-K for the year ended December 31, 1998).
10.6	Form of Indemnity Agreement, between the Company and each officer and director of the Company (incorporated by reference to Exhibit 10.20 to Annual Report on Form 10-K for the year ended December 31, 1991).
10.7	Form of Executive Severance Agreement for the Executive Officers of the Company, effective February 17, 1999 (incorporated by reference to Exhibit 10.12 to Annual Report on Form 10-K for the year ended December 31, 1998).
10.8	Amended and Restated Limited Partnership Agreement of NOARK Pipeline System, Limited Partnership dated January 12, 1998 and amended June 18, 1998 (amended and restated agreement incorporated by reference to Exhibit 10.18 to Annual Report on Form 10-K for the year ended December 31, 1997; first amendment thereto incorporated by reference to Exhibit 10.14 to Annual Report on Form 10-K for the year ended December 31, 1998).
21.	Subsidiaries of the Registrant (filed herewith).
23.	Consent of Arthur Andersen LLP (filed herewith).

Shareholder Information

Annual Meeting

May 15, 2002 at
11:00 a.m. CDT
Northwest Arkansas
Holiday Inn
Springdale, Arkansas

Independent Public Accountants

Arthur Andersen LLP
Tulsa, Oklahoma

SWN Listed NYSE
THE NEW YORK STOCK EXCHANGE

Investor Relations

Greg D. Kerley
Executive Vice President
and Chief Financial
Officer

Brad D. Sylvester
Manager, Investor
Relations
281-618-4700

Web Site

www.swn.com

Transfer Agent and Registrar

EQUISERVE
First Chicago
Trust Division
Post Office Box 2500
Jersey City, NJ
07303-2500
800-446-2617

DirectSERVICE Investment Program

Information about the
Plan is available from
the administrator:
EQUISERVE
Post Office Box 2598
Jersey City, NJ
07303-2598
800-446-2617

Corporate Headquarters

Southwestern Energy
Company
2350 N. Sam Houston
Parkway East, Suite 300
Houston, Texas 77032
281-618-4700
281-618-4818 (fax)

Subsidiary Offices

Southwestern Energy
Production Company
2350 N. Sam Houston
Parkway East, Suite 300
Houston, Texas 77032
281-618-4700
281-618-4818 (fax)

SEECO, Inc.
1083 Sain Street
Post Office Box [illegible]
Fayetteville, Arkansas
72703-1004
479-521-1141
479-521-0328 (fax)

Arkansas Western
Gas Company
1001 Sain Street
Post Office Box 13288
Fayetteville, Arkansas
72703-1002
479-521-5400
479-582-4747 (fax)

Southwestern Energy
Services Company
401 S. Boston
Tulsa, Oklahoma 74103
[illegible]
918-584-4222 (fax)

Forward looking statements – This annual report contains forward-looking statements regarding Southwestern Energy Company's future plans and performance based on assumptions the Company believes are reasonable. A number of factors could cause actual results to differ materially from these statements. For further information regarding these factors, see Management's Discussion and Analysis of Financial Condition and Results of Operations in the Company's 2001 Form 10-K.

Southwestern Energy Company